FITCHBURG GAS AND ELECTRIC LIGHT COMPANY d/b/a UNITIL

Electric Reconciliation Mechanism and Inflation Adjustment Filing

D.T.E. 04-108

TESTIMONY AND SCHEDULES OF KAREN M. ASBURY

ON BEHALF OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY d/b/a UNITIL

Presented to the Massachusetts Department of Telecommunications and Energy

November 24, 2004

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1	I.	INTRODUCTION
2	Q.	Please state your name and business address.
3	A.	My name is Karen M. Asbury. My business address is 6 Liberty Lane West,
4		Hampton, New Hampshire, 03842-1720.
5		
6	Q.	By whom are you employed and what is your title and job responsibility?
7 -	A.	I am Director of Regulatory Services for Unitil Service Corp. ("Service
. 8		Company"), an affiliate of Fitchburg Gas and Electric Light Company d/b/a Unitil
9		("Unitil" or the "Company"). Both companies are members of the Unitil System
10		and subsidiaries of Unitil Corporation. The Service Company provides various
11		professional services, including financial, regulatory and other administrative
12		services to the subsidiaries of Unitil Corporation.
13		
14	Q.	Please briefly describe your educational and business experience.
15	A.	In 1987, I graduated magna cum laude from the University of New Hampshire
16		with a Bachelor of Science Degree in Mathematics. I joined the Service Company
17		in January 1988 and have held various positions in the regulatory/rate department.
18		I have been involved in regulatory compliance and rate analysis for electric and
19		gas utilities for over sixteen years. In my current position, I am responsible for
20		directing regulatory filings, pricing research, analysis, and design, tariff

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1		administration, revenue requirements calculations, customer research, and other
2		analytical services. I have attended several industry seminars and courses,
3		including the Edison Electric Institute's Electric Rate Advanced Course at Indiana
4		University.
5		
6	Q.	Have you previously testified before the Department of Telecommunications and
7		Energy ("Department")?
8	A.	Yes, I have previously testified on numerous occasions before the Department,
9		including prior annual reconciliation filings for Unitil. I have also testified before
10		the New Hampshire Public Utilities Commission and participated in the
11		preparation of filings for the Federal Energy Regulatory Commission.
12		
13	II.	PURPOSE AND BACKGROUND
14	Q.	What is the purpose of your testimony in this proceeding?
15	A.	First, I will provide an overview of Unitil's filing in this proceeding, including a
16		summary of Unitil's proposed tariffs and an introduction of each of Unitil's
17		witnesses that have pre-filed testimony in support of these changes. Next, I will
18		present and explain Unitil's reconciliation models and supporting calculations
19		used to reconcile the costs and actual revenues for the period October 2003
20		through September 2004 for the Standard Offer Service Charge, Default Service

1		Charge, External Transmission Charge, and Internal Transmission Charge. I will
2		also explain these models and supporting calculations used to forecast the costs
3		and revenues for the period October 2004 through December 2005. Finally, I will
4		support Unitil's calculation of its External Transmission Charge and its Internal
5		Transmission Service Cost Adjustment.
6		
7	Q.	Please provide a brief background of Unitil's annual electric reconciliation filings.
8	A.	On January 15, 1999, the Department approved Unitil's Restructuring Plan in
9		D.P.U./D.T.E. 97-115/98-120. On May 5, 1999, July 30, 1999 (as revised on
10		August 27, 1999), and on December 22, 1999, Unitil filed rate changes for its
11		reconciling rate mechanisms in accordance with its plan. The December 22, 1999
12		filing was docketed as D.T.E. 99-110.
13		
14	Q.	Please provide a summary of that docket.
15	A.	In D.T.E. 99-110, the Department undertook a substantive review of Unitil's
16		filing, ruling that this proceeding would be considered Unitil's first reconciliation
17		filing and that the reconciliation period under review would be from March 1,
18		1998 through October 31, 1999. The Department issued its order in this docket
19		on October 18, 2001, ultimately directing Unitil to reconcile its cost adjustment
20		mechanisms for 1998, 1999, 2000, and 2001 based on its findings. On December

1		3, 2001, Unitil filed its next annual reconciliation filing in accordance with the
2		Department's directives, which was docketed as D.T.E. 01-103.
3		
4	Q.	Please summarize the results of that proceeding.
5	A.	On August 15, 2002, Unitil entered into a settlement with the Attorney General,
6		which was subsequently approved by the Department in October 2002. The
7		settlement resolved all outstanding issues related to the calculation and
8		reconciliation of the Transition Charge, the Internal Transmission Charge,
9		External Transmission Charge, Standard Offer Service Charge, and the Default
10		Service Charge for the period March 1998 through September 2001, and the
11		resetting of rates for each of the reconciling mechanisms for effect January 1,
12		2002. The Settling Parties also agreed that the reconciliation methods and
13		calculations to be used by Unitil in its future reconciliation filings shall be in
14		accordance with its compliance filing as modified by the terms of this Settlement
15		
16	Q.	When was Unitil's compliance filing made?
17	A.	On December 22, 2002, Unitil filed its compliance filing, which was also its next
18		annual reconciliation filing, reflecting a reconciliation of costs and revenues for
19		the period October 2001 through September 2002. In this filing, Unitil also
20		implemented changes as a result of its Electric Division's most recent base rate

1 proceeding, D.T.E. 02-24/25. The Department docketed the reconciliation filing 2 as D.T.E. 02-84 and allowed rates to become effective on January 1, 2003, subject to further investigation. The Department's investigation was conducted during 3 2003, and a final order has not yet been issued. A limited number of issues were 4 5 raised by the parties during this investigation. 6 7 Q. Can you please summarize the issues raised by the Attorney General in its brief? 8 A. Yes, there are three. First, the Attorney General raised a concern with a projected 9 discrepancy of \$450,000 which he alleged to be an under-collection from the G-3 class in uniform transition charge revenues. The Attorney General stated that the 10 11 Department should require Unitil to monitor the discrepancy and implement a 12 class-specific transition charge adjustment in 2005 if the actual figures for 2003 13 confirm the projected shortfall. 14 15 Second, the Attorney General claimed that Unitil miscalculated its cash working capital for purchased power costs, and that this miscalculation was attributable to 16 17 a one-day difference in Unitil's lead payment calculation. The Attorney General 18 argued that the Department should require Unitil to increase its lead by one day, resulting in a net lag of 12.49 days. 19

I		The third issue concerned Unitil's recovery of congestion costs through its
2		External Transmission Charge. The Attorney General stated that under Unitil's
3		supply contract, the seller is responsible for congestion costs and the Department,
4		therefore, should deny Unitil's request to recover congestion costs for which the
5		supplier is responsible.
6		
7	Q.	Did Unitil submit another reconciliation filing since the filing made in D.T.E. 02-
8		84?
9	A.	Yes, on November 26, 2003, Unitil submitted its annual reconciliation filing for
10		rates effective January 1, 2004. The Department docketed the filing as D.T.E. 03-
11		115 and allowed the rates to become effective, subject to further investigation.
12		
13	Q.	How have the outstanding issues from D.T.E. 02-84 been addressed in this filing?
14	A.	Given that the outcome of the reconciliation proceeding for 2002 is still pending
15		before the Department, Unitil has not made any changes with respect to its
16		treatment of the issues raised above. However, in D.T.E. 03-115, Unitil analyzed
17		its 2003 year-to-date data regarding the Attorney General's concern with the
18		discrepancy or alleged under-collection of the Transition Charge. Unitil has
19		performed the same analysis for 2004 in this filing. The results are described in
20		the Testimony of Douglas J. Debski.

18	III.	DESCRIPTION OF THE FILING
17		
16		in accordance with the Department's order in D.T.E. 02-24/25.
15		effective December 2002, the date the changes discussed above were implemented
14		proposal of 15.74 days to 13.49 days. This change is reflected in Unitil's filing
13		2003, Unitil agreed to reduce the net lag for working capital from its initial
12	A.	Yes. Please note however that during the hearing in D.T.E. 02-84 on April 7,
11	Q.	Does Unitil's current filing continue to reflect these changes?
10		
9		and Default Service Charge.
8		included generation-related uncollectibles in the Standard Offer Service Charge
7		charges for the Standard Offer Service and Default Service Charge; and 3)
6		balances arising from accrued electric revenues as an offset against the carrying
5		External Transmission Charge; 2) applied the benefits produced by its deferred tax
4		component in its Standard Offer Service Charge, Default Service Charge, and
3	A.	Yes, as fully described in D.T.E. 02-84, Unitil: 1) included a cash working capital
2		Order in D.T.E. 02-24/25?
1	Q.	Can you please summarize the changes implemented as result of the Department's

Please describe the current filing.

Q.

Pursuant to the Restructuring Act and Unitil's Electric Restructuring Plan, Unitil's 1 A. 2 3 4 5 6 7 8 9 10 11 12 13 Q. 14 Α. 15

current filing is designed to implement Unitil's 2005 adjustable rate mechanisms. With this filing, Unitil submits tariffs for its Residential Delivery Service (Schedule RD-1, M.D.T.E. No. 115), Low-Income Residential Delivery Service (Schedule RD-2, M.D.T.E. 116), General Delivery Service (Schedule GD, M.D.T.E. No. 117), and Outdoor Lighting Delivery Service (Schedule SD, M.D.T.E. No. 118). These tariffs reflect a revised Transition Charge calculated to maintain the inflation-adjusted rate cap, while considering changes to Unitil's Internal Transmission Service Cost Adjustment and External Transmission Charge. Unitil is also proposing changes to its Standard Offer Service Fuel Adjustment, which is set outside of the rate cap. Are there any other changes to these tariff pages? Yes, the tariffs also incorporate Unitil's Pension/PBOP Adjustment Factor ("PAF") into the Adjustment provisions of each rate schedule, consistent with the Department's approval of the PAF in D.T.E. 04-48, effective January 1, 2005, for Unitil's electric division. In D.T.E. 04-48, Unitil filed these tariff revisions for informational purposes, indicating that the changes would be incorporated in

conjunction with Unitil's next electric annual reconciliation filing.

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This filing also presents the reconciliation of costs and revenues for the period 2 A. October 2003 through September 2004, and forecast for October 2004 through 3 December 2005, for Unitil's reconciling rate mechanisms. 4 5 6 Q. Given that the Standard Offer Service period ends on February 28, 2005, and the rate cap is lifted, is Unitil proposing any rate changes for effect March 1, 2005, in 7 this filing? 8 No. In this filing, Unitil is only proposing rate changes for effect January 1, 2005. 9 A. 10 The Company intends to follow up with another filing in mid-December to address its plan for recovery of deferred costs beginning March 1, 2005. Unitil's 11 overall approach will be to mitigate rate impacts with respect to recovery of 12 13 deferred costs. Standard Offer Service customers will also see changes in their supply price due to move from Standard Offer Service to Default Service. 14 Unitil's filing will inform the Department on those impacts for its Small Default 15 Service Class, consisting of rate classes RD-1, RD-2, and GD-1. Default Service 16

prices, effective March 1, 2005, for the Large Default Service Class (including

rate classes GD-2, GD-3, GD-4, GD-5, and SD) will not be known until late

January since this class' Default Service price is determined quarterly.

What else is presented in this filing?

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Q.

1 Q. What is the overall impact of the proposed rate changes? 2 Including Unitil's estimated Standard Offer Service Fuel Adjustment ("SOSFA"), A. 3 these rate changes will result in a bill increase of 4.60% to a typical residential customer using 500 kWh per month on Standard Offer Service. As discussed in 4 the Testimony of Douglas Debski, Unitil plans to file and update its SOSFA in 5 early December using actual November data. General Service customers will see 6 7 similar rate increases depending on their particular energy usage characteristics. These rate increases reflect changes to Unitil's reconciling rate mechanisms 8 limited by the inflation adjustment, plus an increase to the SOSFA, which is 9 10 outside the legislative rate cap constraint. Changes in the SOSFA directly impact 11 Unitil's overall rate levels (up or down) during the time period when changes in Unitil's total rate levels are otherwise constrained by the inflation-adjusted rate 12 13 cap. 14 A residential customer using 500 kWh per month on Default Service will see a 15 bill increase of 2.0%. General Service customers will see similar rate increases 16 depending on their particular energy usage characteristics. These increases are 17 due to changes in Unitil's reconciling rate mechanisms limited by the inflation 18 19 adjustment.

- 1 Q. Please describe the primary parts of this filing.
- 2 A. This filing contains:

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- 1. Testimony and Schedules of Karen M. Asbury (Exh. FGE-KMA-1) –

 supporting the reconciliation of costs and revenues for 2004 and

 addressing the cost and revenue forecast for 2005 for the Standard Offer

 Service Charge, Default Service Charge, External Transmission Charge,

 and Internal Transmission Service Cost Adjustment. My testimony also

 provides the computation of proposed rates for the External Transmission

 Charge and Internal Transmission Service Cost Adjustment.
 - 2. Testimony and Schedules of Robyn A. Tafoya (Exh. FGE-RT-1) supporting the reconciliation of costs and revenues for 2004 and addressing the cost and revenue forecast for 2005 for the Transition Charge. Ms. Tafoya also supports the Annual Transition Charge model which is provided in the standardized format.
 - 3. Testimony and Schedules of Douglas J. Debski (Exh. FGE-DJD-1) addressing rate design and calculation of the proposed Transition Charge,
 bill impacts and related exhibits, including justification for the inflation
 adjustment and retail rate cap constraint required under the Restructuring
 Act. Mr. Debski also describes and supports Unitil's 2005 Standard Offer
 Service Fuel Adjustment, which lies outside the rate cap constraint.

1		4. Additional Appendices - providing support and understanding to the filing
2		in the form of Definitions and Acronyms useful to understanding the filing
3		(Appendix A) and Unitil's Restructuring Plan (Appendix B). The
4		Department requires these materials to be filed with the annual
5		reconciliation.
6		
7	Q.	Has Unitil included its workpapers as a part of this filing?
8	A.	Yes, each witness has attached a copy of his or her workpapers as a schedule to
9		their respective testimony.
10		
11	Q.	Has Unitil included a Summary Table of Reconciliation Charges as required by
12		D.T.E. 99-110, that shows the starting and ending balances of the current
13		reconciliation year for all charges?
14	A.	Yes. The Summary Table of Reconciliation Charges is provided in Schedule
15		KMA-1.
16		
17	Q.	What other schedules do you present as part of your testimony?
18	A.	I present the following schedules, in addition to Schedule KMA-1:
19		Schedule KMA-2 – Monthly Standard Offer Service Reconciliation;
20		Schedule KMA-3 – Monthly Default Service Reconciliation;

		Schedule KMA-4 – Monthly External Transmission Charge Reconciliation;
2		<u>Schedule KMA-5</u> – Monthly Internal Transmission Charge Reconciliation.
3		
4	Q.	Do these schedules comply with all other aspects of the Department's Orders
5		issued in Unitil's previous reconciliation filings?
6	A.	Yes, Schedules KMA-2 through KMA-5 comply with previous Department
7		directives from D.T.E. 01-103 and D.T.E. 99-110 pertaining to the calculation and
8		reconciliation of these charges.
9 10	IV.	STANDARD OFFER SERVICE CHARGE AND RECONCILIATION
11 12	Q.	What are the Standard Offer Service Charge and the Standard Offer Service
	Q.	What are the Standard Offer Service Charge and the Standard Offer Service Adjustment?
12	Q.	<u> </u>
12 13		Adjustment?
12 13 14		Adjustment? The Standard Offer Service ("SOS") Charge and the Standard Offer Service
12 13 14 15		Adjustment? The Standard Offer Service ("SOS") Charge and the Standard Offer Service Revenue Reconciliation Adjustment together recover Unitil's direct SOS Costs.
12 13 14 15 16		Adjustment? The Standard Offer Service ("SOS") Charge and the Standard Offer Service Revenue Reconciliation Adjustment together recover Unitil's direct SOS Costs. There was an interim period during which Unitil supplied energy from its existing
12 13 14 15 16		Adjustment? The Standard Offer Service ("SOS") Charge and the Standard Offer Service Revenue Reconciliation Adjustment together recover Unitil's direct SOS Costs. There was an interim period during which Unitil supplied energy from its existing portfolio to retail customers, beginning March 1, 1998. In particular, during the

- 1 Q. Does Unitil continue to provide SOS service?
- 2 A. No, it does not. In March of 1999, Unitil began acquiring SOS pursuant to a
- fully competitive bidding process -- from Constellation Power Source under a
- 4 contract approved by the Department. D.T.E. 97-115/98-120 (1999).

- 6 Q. Please match the costs that have been included in the SOS mechanism with the
- associated sections of Unitil's approved Restructuring Plan and other relevant
- 8 orders. Also, provide the location of these costs in your schedules.
- 9 A. This information is provided in Table KMA-1, below. The table only includes
- 10 cost elements that apply in the period being presented.

TABLE KMA-1			
Line #	Costs from SCHEDULE KMA-2, Pages 4-5	Correlation to Restructuring Plan or subsequent orders	
5.	Cost of Constellation Power Source Contract	❖ See Unitil's Restructuring Plan, Appendix B. Tab D, Page V2 − V4 for the approved competitive acquisition of power supply for SOS. Consistent with the Plan, Unitil sought and received approval for its competitively bid standard offer service contract with Constellation Power Source in Docket 98-120. D.T.E./D.P.U. 97-115/98-120 (1999).	
6.	Renewable Energy Certificates	The title to or claim for the generation attributes associated with a Renewable Generator that is compliant with the definition of a New Renewable Generation Source as found in 225 CMR 14.00 – Renewable Energy Portfolio Standard. Unitil began incurring these costs in January 2003. Filed in D.T.E. 02-84. See Unitil Tariff M.D.T.E. No. 99.	
7.	Working Capital	Recovery provided per DTE Order dated December 2, 2002 in DTE 02-24/25.	

		See SCHEDULE KMA-2, Page 6 of 8 for the calculation of Working Capital.
8.	Bad Debt Costs	 Recovery provided per DTE Order dated December 2, 2002 in DTE 02-24/25. See SCHEDULE KMA-2, Page 8 of 8 for
		calculation of Standard Offer Service bad debt allocation factor.

- 2 Q. What reconciliation period is included in this filing?
- 3 A. The filing includes actual costs and revenues from January 2003 through
- 4 September 2004 and estimated data from October 2004 through February 2005.

5

- 6 Q. For what period has the Department approved cost recovery?
- 7 A. The Department has approved recovery of costs through September 2001 (D.T.E.
- 8 01-103-A at 7). Costs from October 2001 through September 2002 were
- 9 reviewed in D.T.E. 02-84, which remains pending. Costs from October 2002
- through September 2003 were filed in D.T.E. 03-115 for which an investigation is
- pending. Since the cost data from October 2003 through December 2003 are
- subject to review as part of this filing, rather than present partial year data, Unitil
- is presenting the full year.

- 15 Q. Are there any changes to the presentation of the cost recovery mechanisms from
- that provided in D.T.E. 03-115?
- 17 A. No.

1	Q.	What is Unitil's proposed Standard Offer Service Revenue Reconciliation
2		Adjustment ("SOSRRA") for effect January 1, 2005?
3	A.	Unitil proposes that its SOSRRA be \$0.00000 per kWh effective January 1, 2005.
4		
5	Q.	Is there a balance at December 31, 2004 in the Standard Offer Service account?
6	A.	Yes.
7		
8	Q.	If there is a balance at year-end in this account, why has Unitil proposed that the
9		Department set a rate of \$0.00000 per kWh on January 1, 2005?
10	A.	The Transition Charge has a much higher year-end deferral and has a higher
11		interest charge on deferrals than Standard Offer Service. Since there is not
12		enough "headroom" under the rate cap established by the Electric Restructuring
13		Act to collect the entire balance in both accounts, Unitil proposes to continue to
14		prioritize its recoveries in order to collect first the costs that are more expensive to
15		customers (e.g., the under-collection in the Transition Charge account). By doing
16		so, Unitil will lessen the impact on customers in the future by eliminating the
17		balance with the higher carrying charge. Unitil believes this is the most
18		reasonable method for ensuring the least cost to customers, while at the same time
19		adhering to the requirements of the Electric Restructuring Act's price cap.

2 A. As shown on Schedule KMA-2, Page 3, the indicated SOSRRA is \$0.06085 per 3 kWh. The indicated SOSRRA is so high because there are only two months remaining in the period to recover the deferral. 4 5 What is the base Standard Offer Service rate effective January 1, 2005? 6 Q. 7 A. In accordance with Unitil's Standard Offer Service Tariff, M.D.T.E. No. 99, the 8 base Standard Offer Service rate remains at \$0.05100 per kWh. 9 Please describe Schedule KMA-2. 10 O. Schedule KMA-2 is Unitil's Monthly Standard Offer Service Reconciliation. This 11 A. 12 schedule contains 8 pages. Pages 1 and 2 provide the calculation of interest and monthly deferrals for 2003 through February, 2005. As discussed above, page 3 13 14 provides the calculation of the indicated SOSRRA. Pages 4 and 5 provide the 15 monthly cost detail. Page 6 provides the calculation of working capital costs. Page 7 provides a forecast of revenues for the period October 2004 through 16 February 2005. Page 8 provides the updated bad debt allocation factor for SOS. 17 Consistent with the Department's determination in D.T.E. 99-110, for purposes of 18 19 reconciliation, Unitil has provided actual data through September 2004. The 20 remainder is forecast.

What would the SOSRRA be if there were no rate level constraints?

1

Q.

1		
2	Q.	Please describe Page 8 in further detail.
3	A.	Page 8 provides the updated bad debt allocation factor for SOS. As provided for
4		in Unitil's SOS tariff, M.D.T.E. No. 99 and the Department's Order in D.T.E. 02-
5		24/25, the allocation factor is required to be updated annually in Unitil's
6		reconciliation proceedings. The allocation factor used by Unitil beginning
7		December 2002 through December 2003, as reflected in D.T.E. 02-84, is based on
8		2001 calendar year data. The allocation used by Unitil for the January-to-
9		December 2004 period is based on 2002 calendar year data. The allocation factor
10		for the January-to-December 2005 period has been updated and is based on 2003
11		calendar year data. In future filings, Unitil would continue to update its allocation
12		factor on data from the prior calendar year.
13		
14	Q.	What is the expected balance at the end of February 2005?
15	A.	With the proposed SOSRRA of \$0.00000 per kWh effective January 1, 2005, the
16		balance is projected to be an under-collection of \$2,643,074 as shown on Page 2.
17		As indicated above, Unitil intends to file a plan in mid-December to address
18		recovery of deferred costs beginning March 1, 2005 when the rate cap is lifted.
19		

1	Q.	In D.T.E. 02-40-B, the Department directed each distribution company, in all
2		future default service and standard offer service filings, to fully describe the
3		manner in which it has complied, or intends to comply, with its Renewable
4		Portfolio Standards ("RPS") obligations. Please describe Unitil's compliance
5		with respect to its RPS obligations.
6	A.	With respect to Default Service, with each of its filings in D.T.E. 99-60,
7		beginning with its October 22, 2003 filing, Unitil has explained its compliance
8		plan in detail. In summary, Unitil intends to purchase qualifying Renewable
9		Energy Credits ("RECs") directly from the market or under a process that is
10		separate from its Default Service solicitations.
11		
12		With respect to Standard Offer Service, as indicated in D.T.E. 02-84, Unitil
13		entered into a contract with CSG Services to fulfill its 2003 obligations. Unitil's
14		future compliance strategy is the same for both Default Service and Standard
15		Offer Service. Unitil has and will continue to regularly test the market through a
16		variety of means (issuing and responding to Requests For Proposals, use of
17		brokers, direct negotiations) for as long as it has an outstanding compliance
18		obligation.

Unitil believes that the market for Massachusetts qualifying RECs is currently illiquid, and that by the time Unitil is required to demonstrate compliance, opportunities may arise to purchase RECs either from facilities that are not at the moment registered as qualifying Massachusetts new renewable facilities or from entities who come to have excess RECs after meeting their obligations. Unitil also expects that it may be able to receive more favorable RECs pricing if the periods for which RECs are sought are flexible. For example, Unitil's ability as a load serving entity to bank RECs in its New England Generation Information System account is expected to allow Unitil to utilize the RECs it acquires efficiently, rather than requiring pricing based on a specific delivery period. Unitil also expects that combining the volumes of service under its Default Service and Standard Offer Service would yield better pricing opportunities in the market.

V. DEFAULT SERVICE CHARGE AND RECONCILIATION

- 16 Q. What is the Default Service Charge and what is it intended to accomplish?
- 17 A. The Default Service Charge recovers costs approved by the Department as part of
- Unitil's Restructuring Plan (Appendix B, Tab D, Page IV.5). The Default Service
- 19 Charge reflects the cost of acquiring power supply from the competitive market.

- 1 Q. How has Unitil acquired the Default Service supply that it has sold under this 2 rate?
- A. Beginning December 2000, Unitil has acquired its Default Service supply through
 a Department-approved competitive market solicitation.

- Q. Please match the costs that have been included in the Default Service mechanism
 with the associated sections of Unitil's approved Restructuring Plan and other
 relevant orders. Also, provide the location of these costs in your schedules.
- 9 A. This information is provided in Table KMA-2, below. The table includes only cost elements that apply in the period being presented.

	TABLE KM	A - 2
Line #	Costs from SCHEDULE KMA-3, Pages 3-4	Correlation to Restructuring Plan or subsequent orders
8.	Sales for Resale (adjustments in February 2003)	 ❖ When Constellation began serving the SOS load, beginning March 1, 1999, sales for resale are recovered and reconciled in the Default Service Charge, during the period that Unitil continued to manage a portfolio to supply Default Service (March 1999 - December 2000). ❖ See Unitil's Restructuring Plan, Appendix B, Tab D, Page V2, item (2) for the approved description of Unitil's use of its power supply portfolio to provide SOS and DS prior to that load being served by external suppliers. ❖ See also DTE Order dated December 2, 2002, in DTE 02-24/25 in which the Department indicated it will consider recovery of costs associated with power supply expenses in its reconciliation filing.
9.	Default Service Supplier Costs	Beginning December, 2000 Unitil received approval to use an external Default Service supplier that was acquired through a

			competitive market solicitation. These costs represent the cost of Default Service supplied by external Default Service suppliers.
10.	Working Capital	*	Recovery provided per DTE Order dated December 2, 2002, in DTE 02-24/25. See SCHEDULE KMA-3, page 5 of 7 for the calculation of Working Capital.
11.	Bad Debt Costs	* *	Recovery provided per DTE Order dated December 2, 2002, in DTE 02-24/25. See SCHEDULE KMA-3, page 7 of 7 for calculation of the bad debt allocation factor.
12.	Renewable Energy Certificates	*	The title to or claim for the generation attributes associated with a Renewable Generator that is compliant with the definition of a New Renewable Generation Source as found in 225 CMR 14.00 – Renewable Energy Portfolio Standard. Prior to December 2003, Unitil's Default Service provider was responsible for these costs. Recovery approved in D.T.E. 99-60, October 30, 2003. See Unitil Tariff M.D.T.E. No. 103.

2 Q. What reconciliation period is included in this filing?

1

- 3 A. The filing includes actual costs and revenues from January 2003 through
- 4 September 2004, and estimated data from October 2004 through December 2005.
- 6 Q. For what period has the Department approved cost recovery?
- 7 A. The Department has approved recovery of costs through September 2001 (D.T.E.
- 8 01-103-A at 7). Costs from October 2001 through September 2002 were
- 9 reviewed in D.T.E. 02-84, which remains pending. Costs from October 2002
- through September 2003 were filed in D.T.E. 03-115 for which an investigation is
- pending. Since cost data for October 2003 through December 2003 are required

1		as part of this filing, rather than present partial year data, Unitil is presenting the
2		full year.
3		
4	Q.	Are there any changes to presentation of the cost recovery mechanisms from that
5		provided in D.T.E. 03-115?
6	A.	No.
7		
8	Q.	What is Unitil's proposed Default Service Adjustment for effect January 1, 2005?
9	A.	Unitil proposes that its Default Service Adjustment be \$0.00000 per kWh
10		effective January 1, 2005.
11		
12	Q.	Is there a balance at December 31, 2004 in the Default Service account?
13	A.	Yes.
14		
15	Q.	If there is a year-end balance in this account, why has Unitil proposed that the
16		Department set a rate of \$0.00000 per kWh effective January 1, 2005?
17	A.	The Transition Charge has a much higher year-end deferral and has a higher
18		interest charge of deferrals than Default Service. Similar to the discussion above
19		concerning SOS, since there is not enough headroom under the rate cap
20		established by the Electric Restructuring Act to collect the entire balance in both

1 accounts, Unitil proposes to continue to prioritize the recovery in order to collect first the costs that are more expensive to customers (e.g., the under-collection in 2 the Transition Charge account). 3 4 5 Q. How is Unitil's Default Service Charge set? 6 A. The Default Service Charge is set at the same time that Unitil selects a winning 7 bidder from periodic solicitations in compliance with Department directives. The 8 Default Service Charge is filed with the Department for approval and currently 9 reflects the supplier cost, RECs cost, and losses. On November 17, 2003, the 10 Department issued an order identifying other costs to be included in default 11 service rates and requiring distribution companies to submit compliance filings 12 within six weeks. Since Unitil's proposal is pending in that docket, no changes 13 have been made to the tariffs or rates in context of its periodic Default Service rate filings. 14 15 Q. Please describe Schedule KMA-3. 16 17 A. Schedule KMA-3 is Unitil's Monthly Default Service Reconciliation. This 18 schedule contains 7 pages. Pages 1 and 2 provide the calculation of interest and monthly deferrals for 2003 through 2005. Pages 3 and 4 provided the monthly 19 cost detail. Page 5 provides the calculation of working capital costs. Page 6 20

- provides a forecast of revenues for the period October 2004 through December 1 2005. For simplicity, the forecast uses the Default Service prices that become 2 effective on December 1, 2004. Page 7 provides the updated bad debt allocation 3 factor for Default Service. As discussed above, the allocation factor is required to 4 be updated annually in Unitil's reconciliation proceedings. As shown on page 4, 5 6 effective March 1, 2005, Unitil has included both the Standard Offer Service allocation factor and Default Service allocation factor in determining the Default 7 Service costs reflective of the fact that Standard Offer Service customers will 8 move to Default Service. Consistent with the Department's determination in 9 10 D.T.E. 99-110, for its reconciliation, Unitil has provided actual data through September 2004. The remainder is forecast. 11 12 13 Q. What is the expected balance at the end of 2005? 14 A. The balance is projected to be an under-collection of \$2,612,330, as shown on Page 2. As indicated above, Unitil intends to file a plan in mid-December to 15 address recovery of deferred costs beginning March 1, 2005 when the rate cap is 16 lifted. 17

EXTERNAL TRANSMISSION CHARGE

20 Q. What is the External Transmission Charge?

18

19

VI.

1 A. As provided in Unitil's current tariff, M.D.T.E. No. 97, the External Transmission Charge recovers all external transmission costs that are billed to Unitil by any 2 other transmission provider, other regional transmission or operating entities, such 3 as NEPOOL, a regional transmission group, an independent system operator, or 4 other regional bodies. It also recovers charges related to the stability of the 5 6 transmission system. Costs beyond the NEPOOL PTF system are the direct obligation of the Competitive Suppliers serving Unitil's customers. Effective 7 8 December 1, 2002, the External Transmission Charge also recovers working capital costs. 9 10 Please match the costs that have been included in the External Transmission 11 Q. Charge mechanism with the associated sections of Unitil's approved 12 13 Restructuring Plan and other relevant orders. Also, provide the location of these costs in your schedules. 14

	TABLE KMA-3		
Column	Costs from SCHEDULE KMA-4, Pages 1-3	Correlation to Restructuring Plan	
A.	ISO EXPENSES - EFC Relabeled ISO ADMINISTRATIVE COSTS - Effective October 2001	❖ See Unitil approved Restructuring Plan, Appendix B, Tab D, pages IV.3 and IV.4, 2. <u>Transmission Charges:</u> "The External Transmission Charge will recover on a fully reconciling basis the FERC-approved billings to the Company associated with the Regional Transmission Group, an Independent System Operator or any other transmission provider	

This information is provided in Table KMA-3, below.

15

A.

		and which the Company has authorization to recover from retail customers."
B.	NEP COMPREHENSIVE TRANSMISSION	❖ See A above.
C.	NEPOOL RN/TRANS. COSTS	❖ See A above.
D.	CONGESTION PURCHASES	❖ See A above.
E.	CONGESTION SALES	❖ See A above.
F.	OVER-DESIGNATION SALES	❖ See A above.
G.	NEP TRANS CREDIT	❖ See A above.
H.	MAINE ELECTRIC (NEW BRUNSWICK POWER)	See A above.
I.	COST OF WORKING CAPITAL	 Recovery provided per DTE Order dated December 2, 2002 in DTE 02-24/25. See SCHEDULE KMA-4, page 6 of 7 for the calculation of Working Capital.

- 2 Q. What reconciliation period is included in this filing?
- 3 A. The filing includes actual costs and revenues from January 2003 through
- 4 September 2004, and estimated data from October 2004 through December 2005.

5

- 6 Q. For what period has the Department approved cost recovery?
- 7 A. The Department has approved recovery of costs through September 2001 (D.T.E.
- 8 01-103-A at 7). Costs from October 2001 through September 2002 were
- 9 reviewed in D.T.E. 02-84, which remains pending. Costs from October 2002
- through September 2003 were filed in D.T.E. 03-115 for which an investigation is
- pending. Since cost data for October 2003 through December 2003 are required
- as part of this filing, rather than present partial year data, Unitil is presenting the
- full year.

1	Q.	Are there any other changes to presentation of the cost recovery mechanisms from
2		D.T.E. 03-115?
3	A.	No.
4		
5	Q.	What is Unitil's proposed External Transmission Charge?
6	A.	Unitil's proposed External Transmission Charge is \$0.00406 per kWh as shown
7		on Page 3 of Schedule KMA-4.
8		
9	Q.	How does this compare to Unitil's current External Transmission Charge?
10	A.	The current External Transmission Charge is \$0.00308 per kWh. The proposed
11		rate is \$0.00098 per kWh higher than the current rate. This reflects increased
12		costs, which have caused an under-recovery of costs for 2004 and an increased
13		cost projection for 2005. The increase is driven by an increase in the cost of
14		regional transmission service, which is due to the expansion of the regional
15		transmission grid for the purpose of increasing reliability and increased costs of
16		reactive supply and voltage control from generation sources.
17		
18	Q.	How is the External Transmission Charge calculated?
19	A.	Consistent with Unitil's External Transmission Charge Tariff, the charge is
20		calculated based on a forecast of costs for 2005, with full reconciliation and

1		interest for any over- or under-recoveries in 2004. This calculation is
2		demonstrated on Page 3 of Schedule KMA-4.
3		
4	Q.	Is this the same methodology approved in D.T.E. 99-110 and D.T.E. 01-103?
5	A.	Yes.
6		
7	Q.	Please describe Schedule KMA-4.
8	A.	Schedule KMA-4 is Unitil's Monthly External Transmission Charge
9		Reconciliation. This schedule contains 7 pages. Pages 1 through 3 provide the
10		monthly and annual cost detail and end of year deferrals for 2003 through 2005
11		As discussed above, page 3 also provides the calculation of the proposed rate.
12		Pages 4 and 5 provide the calculation of interest and monthly deferrals for 2003
13		through 2005. Page 6 provides the calculation of working capital costs. Page 7
14		provides a forecast of revenues for the period October 2004 through December
15		2005. Consistent with the Department's determination in D.T.E. 99-110, Unitil
16		has provided actual data through September 2004. The remainder is forecast.
17		
18	Q.	What is the proposed reconciliation amount?

1	A.	As shown on Page 4, the proposed reconciliation amount is an under-collection of
2		\$275,596 based on actual data through September 2004, and forecast data through
3		December 2004.
4		
5	Q.	What is the expected balance at the end of 2005?
6	A.	With the proposed External Transmission Charge of \$0.00406 per kWh effective
7		January 1, 2005, the balance is projected to be an under-collection of \$1,480 as
8		shown on Page 5.
9		
10	Q.	Are there any other considerations you would like to make special note of?
11	A.	Yes, the cost forecast does not reflect any changes that may result from the
12		Regional Transmission Organization-New England filing made with the Federal
13		Energy Regulatory Commission (Docket Nos. RT04-2 and ER04-116) on October
14		31, 2003, or the companion Transmission Owners Return on Equity Filing
15		(Docket No. ER04-157) made on November 3, 2003. Based on the most recent
16		series of FERC decisions in early November 2004, the Regional Transmission
17		Organization may go into effect some time in early 2005. However, the impact on
18		rates and the impact that the return on equity will have associated with those rates
19		is still unknown. Unitil has not reflected these in its forecast since the starting

1		date is undetermined and due to the difficulty in calculating and presenting an
2		estimate that may be reasonably supported at this time.
3		
4	VII.	INTERNAL TRANSMISSION SERVICE COST ADJUSTMENT
5	Q.	What are the Internal Transmission Charge and the Internal Transmission Service
6		Cost Adjustment?
7	A.	The Internal Transmission Charge, along with the Internal Transmission Service
8		Cost Adjustment, recovers on a fully reconciling basis all costs associated with
9		Unitil's transmission investments.
10		
11	Q.	Is this recovery approved by the Department and resident in any tariff filed by
12		Unitil?
13	A.	Yes, it is. The Department approved the Internal Transmission Service Cost
14		Adjustment as part of Unitil's Restructuring Plan (Appendix B, Tab G, M.D.T.E.
15		No. 14), allowing the recovery, on a fully reconciling basis, of all transmission
16		charges applicable to retail customers under Unitil's FERC-approved Open Access
17		Transmission Tariff (OATT).
18		
19	Q.	Does the recovery permit Unitil to recover any other transmission-related costs?

1	A.	Yes. It may recover all those costs applicable to Unitil's Pool Transmission
2		Facilities (PTF) revenue requirement as included in NEPOOL's OATT.
3		
4	Q.	When the Regional Transmission Organization becomes effective, will Unitil's
5		Internal Transmission Service Cost Adjustment tariff be revised?
6	A.	Yes, Unitil expects to file a revised tariff to reference the Regional Transmission
7		Organization tariff in place of the NEPOOL OATT. In addition, local service
8		currently provided under Unitil's OATT, will be incorporated into the Regional
9		Transmission Organization tariff.
10		
11	Q.	Will this be a change in the cost elements that Unitil seeks to recover through the
12		Internal Transmission Service Cost Adjustment?
13	A.	No. The change is simply to update the tariff to reflect the Regional Transmission
14		Organization structure.
15		
16	Q.	What kinds of transmission investments does Unitil have?
17	A.	Unitil's transmission investments are divided into two components, Non-Pool
18		Transmission Facilities (Non-PTF) and Pool Transmission Facilities (PTF).
19		
20	Q.	What are PTF?

PTF are those facilities that Unitil owns that are defined by NEPOOL and 1 A. 2 included in the provision of transmission service through NEPOOL's Open Access Transmission Tariff (OATT). 3 4 What facilities constitute Non-PTF? 5 Q. 6 A. The remainder of Unitil's transmission investment other than facilities described 7 above is considered Non-PTF. These costs are included in the provision of transmission service through Unitil's local OATT. 8 9 10 Q. Please match the costs that have been included in the Internal Transmission Charge mechanism with the associated sections of Unitil's approved 11 Restructuring Plan and other relevant orders. Also, provide the location of these 12 13 costs in your schedules.

TABLE KMA - 4		
Column	Costs from SCHEDULE KMA-5, Pages 1-3	Correlation to Restructuring Plan
A.	Revenue Requirement (OATT)	❖ See Unitil's approved Restructuring Plan, Appendix B, Tab D, page IV.3, 2. <u>Transmission Charges:</u> "the Internal Transmission Cost Adjustment will recover on a fully reconciling basis: 1) the transmission charges applicable to retail customers under the Company's FERC-approved Open Access Transmission Tariff"
В.	Revenue Requirement (PTF)	 See Restructuring Plan, Appendix B, Tab D, 2. Transmission Charges, page IV.3: "the

This information is provided in Table KMA-4, below.

A.

Fitchburg Gas and Electric Light Company d/b/a Unitil
Electric Reconciliation Mechanism and Inflation Adjustment Filing
D.T.E. 04-108
Exh. FGE-KMA-1
Page 34 of 37

		Internal Transmission Cost Adjustment will recover on a fully reconciling basis: 1) the transmission charges applicable to retail customers under the Company's FERC-approved Open Access Transmission Tariff; and 2) the Company's Pool Transmission Facilities revenue requirement as included in NEPOOL's Open Access Transmission Tariff"	
1			
2	Q.	When do Unitil's Open Access ("OA") costs normally change?	
3	A.	Effective October 1, 2003, in accordance with Unitil's OA Transmission Tariff,	
4		the revenue requirement is updated annually, effective June 1 each year. Prior to	
5		October 1, 2003, the revenue requirement was based on a test year amount, and	
6		therefore changes were made only upon filing and approval by FERC.	
7			
8	Q.	When do Unitil's PTF costs normally change?	
9	A.	In accordance with NEPOOL's OATT, the revenue requirements are updated	
10		annually, effective June 1 of the following year. Therefore, Unitil updates the	
11		monthly amounts it uses in its reconciliation effective June 1 each year to	
12		correspond with NEPOOL's changes.	
13			
14	Q.	What reconciliation period is included in this filing?	
15	A.	The filing includes actual cost and revenues from January 2003 through	
16		September 2004, and estimated data from October 2004 through December 2005.	

1	Q.	For what period has the Department approved cost recovery?
2	A.	The Department has approved recovery of costs through September 2001 (D.T.E.
3		01-103-A at 7). Costs from October 2001 through September 2002 were
4		reviewed in D.T.E. 02-84, which remains pending. Costs from October 2002
5		through September 2003 were filed in D.T.E. 03-115 for which an investigation is
6		pending. Since cost data for October 2003 through December 2003 are required
7		as part of this filing, rather than present partial year data, Unitil is presenting the
8		full year.
9		
10	Q.	Any there any other changes to presentation of the cost recovery mechanisms from
11		D.T.E. 03-115?
12	A.	No.
13		
14	Q.	What is Unitil's proposed Internal Transmission Service Cost Adjustment?
15	A.	Unitil's proposed Internal Transmission Service Cost Adjustment is \$0.00099 per
16		kWh, as shown on Page 3 of Schedule KMA-5.
17		
18	Q.	How does this compare to Unitil's current Internal Transmission Service Cost
19		Adjustment?

1	A.	Unitil's current Internal Transmission Service Cost Adjustment is \$0.00044 per
2		kWh. The proposed rate is increasing by \$0.00055 per kWh. The increase is due
3		primarily due to an increase Unitil's OA revenue requirement effective June 1,
4		2004. The current revenue requirement was to estimate the revenue requirement
5		effective June 1, 2005 as well.
6		
7	Q.	How is the Internal Transmission Service Cost Adjustment calculated?
8	A.	Consistent with Unitil's Internal Transmission Service Cost Adjustment Tariff, the
9		charge is calculated based on a forecast of costs for 2005, with full reconciliation
10		and interest for any over- or under- recoveries in 2004. This calculation is
11		demonstrated on Page 3 of Schedule KMA-5.
12		
13	Q.	Is this the same methodology approved in D.T.E. 99-110 and D.T.E. 01-103-A?
14	A.	Yes.
15		
16	Q.	Please describe Schedule KMA-5.
17	A.	Schedule KMA-5 is Unitil's Monthly Internal Transmission Charge
18		Reconciliation. This schedule contains 7 pages. Pages 1 through 3 provide the
19		monthly and annual cost detail and end of year deferrals for 2003 through 2005.
20		Page 3 provides forecasted cost data for 2005. As discussed above, page 3 also

1		provides the calculation of the proposed rate. Pages 4 through 5 provide the
2		calculation of interest and monthly deferrals for 2003 through 2005. Pages 6 and
3		7 provide the forecast of revenues for the period October 2004 through December
4		2005. Consistent with the Department's determination in D.T.E. 99-110, Unitil
5		has provided actual data through September 2004. The remainder is forecast.
6		
7	Q.	What is the proposed reconciliation amount?
8	A.	As shown on Page 4, the proposed reconciliation amount is an under-collection of
9		\$113,351 based on actual data through September 2004, and forecast data through
10		December 2004.
11		
12	Q.	What is the expected balance at the end of 2005?
13	A.	With the proposed Internal Transmission Service Cost Adjustment of \$0.00099
14		per kWh effective January 1, 2005, the balance is projected to be an under-
15		collection of \$1,888, as shown on Page 5.
16	VIII.	CONCLUSION
17	Q.	Does this conclude your testimony?
18	A.	Yes.

SUMMARY TABLE OF RECONCILIATION CHARGES

Summary Table of Reconciliation Charges^(a)

	Present Charge	Proposed Charge	Balance at End of Previous Reconciliation Year, Dec 2004	Balance at Beginning of Current Reconciliation Year, Jan 2005	Balance at End of Current Reconciliation Year, Dec 2005*	
Transition Charge Standard Offer Service Revenue	\$0.00982	\$0.01049	\$21,571,339	\$21,571,339	\$26,629,286	(b)
Reconciliation Adjustment	\$0.00000	\$0.00000	\$2,572,663	\$2,572,663	\$2,643,074	(c)
Default Service Adjustment	\$0.00000	\$0.00000	\$1,987,648	\$1,987,648	\$2,612,330	(d)
External Transmission	\$0.00308	\$0.00406	\$275,596	\$275,596	\$1,480	(e)
ITSCA	\$0.00044	\$0.00099	\$113,351	\$113,351	\$1,888	(f)

^{*} Reflects balance at end of February 2005 for Standard Offer Service.

- (a) <u>Fitchburg Gas and Electric Light Co.</u>, D.T.E. 99-110 at 52, item (3). The summary table lists the starting and ending balances of the current reconciliation year for all charges.
- (b) Exh. FGE-1 (RT), Sch. RT-3.
- (c) Exh. FGE-1 (KMA), Sch. KMA-2.
- (d) Exh. FGE-1 (KMA), Sch. KMA-3.
- (e) Exh. FGE-1 (KMA), Sch. KMA-4.
- (f) Exh. FGE-1 (KMA), Sch. KMA-5.

MONTHLY STANDARD OFFER SERVICE RECONCILIATION

chburg Gas and Electric Light Company d/b/a Unitil andard Offer Service Deferral and Interest Calculation - Monthly	Standa	rd Offer Servic	ce R	econciliation											SCHEDUL	ege 1	
nuary 2003 - December 2003		Jan-03 <u>Actual</u>		Feb-03 <u>Actual</u>	Mar-03 <u>Actual</u>	Apr-03 <u>Actual</u>	May-03 <u>Actual</u>		Jun-03 <u>Actual</u>	Jul-03 <u>Actual</u>	Aug-03 <u>Actual</u>	Sep-03 Actual	Oct-03 <u>Actual</u>	Nov-03 <u>Actual</u>	Dec-03 <u>Actual</u>		Total
tal Costs (See page 4)	\$	1,066,351	\$	1,035,616 \$	997,630 \$	1,073,924 \$	815,756	\$	937,376 \$	1,116,639 \$	1,217,321 \$	995,789 \$	911,921	\$ 607,493 \$	884,934	\$ 1	11,660,751
)S Revenue)SRRA Revenue	\$ \$	1,222,988	\$	1,083,100 \$ - \$	1,065,302 \$ - \$	982,158 \$ - \$	-	\$ \$	958,931 \$ - \$	1,168,472 \$ - \$	1,195,916 \$ - \$	1,068,528 \$ - \$	884,142 -	\$ - \$	956,438 \$ - \$	\$	12,388,060
tal Revenues	\$	1,222,988	\$	1,083,100 \$	1,065,302 \$	982,158 \$	939,062	\$ 9	958,930.93 \$	1,168,472 \$	1,195,916 \$	1,068,528 \$	884,142	\$ 863,023 \$	956,438	\$ 1	12,388,060
ver)/Under Recovery - Month	\$	(156,637)	\$	(47,484) \$	(67,671) \$	91,766 \$	(123,306)	\$	(21,555) \$	(51,833) \$	21,405 \$	(72,739) \$	27,778	\$ (255,530) \$	(71,504)		
MULATIVE (OVER)/UNDER RECOVERY ginning Balance	\$	3.289.399	s	3,139,906 \$	3,098,685 \$	3.037.832 \$	3,136,238	\$	3,019,773 \$	3,004,696 \$	2.959.491 \$	2.987,505 \$	2,921,121	\$ 2,955,046 \$	2,705,245		
ding Balance Before Interest	\$	3,132,761	\$	3,092,422 \$	3,031,013 \$	3,129,598	3,012,932	\$	2,998,218 \$	2,952,864 \$	2,980,897 \$	2,914,767 \$	2,948,899		2,633,742		
erage Monthly Balance erest Rate (1)	\$	3,211,080 2.62%	\$	3,116,164 \$ 2.62%	3,064,849 \$ 2.62%	3,083,715 \$ 2.62%	3,074,585 2,62%	\$	3,008,995 \$ 2,62%	2,978,780 \$ 2.62%	2,970,194 \$ 2.62%	2,951,136 \$ 2.62%	2,935,010 2,47%	\$ 2,827,281 \$ 2.47%	2,669,493 2.47%		
mber of Days / Month		31		28	31	30	31		30	31	31	30	31	30	2.47 /6		365_
mputed Interest	\$	7,144	\$	6,262 \$	6,819 \$	6,640 \$	6,841	\$	6,478.90 \$	6,627.64 \$	6,609 \$	6,354 \$	6,146	\$ 5,730 \$	5,590	\$	77,242
ding Balance with Interest	\$	3,139,906	\$	3,098,685 \$	3,037,832 \$	3,136,238 \$	3,019,773	\$	3,004,696 \$	2,959,491 \$	2,987,505 \$	2,921,121 \$	2,955,046	\$ 2,705,245 \$	2,639,332		

Effective December 2002, includes credit for deferred income taxes, Prime rate * (1-t) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002.

chburg Gas and Electric Light Company d/b/a Unitil andard Offer Service Deferral and Interest Calculation - Monthly nuary 2004 - December 2004	Standa	rd Offer Servi Jan-04 <u>Actual</u>	ce R	econciliation Feb-04 <u>Actual</u>	Mar-04 <u>Actual</u>	Apr-04 <u>Actua</u> j	May-04 <u>Actual</u>		Jun-04 <u>Actual</u>	Jul-04 <u>Actual</u>		Aug-04 Actual	Sep-04 <u>Actual</u>		Oct-04 <u>Stimated</u>		Nov-04 stimated		Dec-04 Estimated	Total
tal Costs (See page 5)	\$	1,019,874	\$	855,170 \$	894,623 \$	815,685 \$	951,689	\$	966,622 \$	757,671	\$	941,675 \$	824,068	\$	840,064	\$	963,260	\$	1,068,442	\$ 10,898,843
)S Revenue (See page 7))SRRA Revenue (See page 7)	\$ \$	1,014,956	\$ \$	993,810 \$ - \$	927,507 \$ - \$	879,642 \$ - \$	793,729 -	\$ \$	856,471 \$ - \$	904,641	\$ \$	949,538 \$	928,724	\$ \$	830,101	\$ \$	894,031	\$ \$	1,057,545	\$ 11,030,695
tal Revenues (See page 7)	\$	1,014,956	\$	993,810 \$	927,507 \$	879,642 \$	793,729	\$	856,471 \$	904,641	\$	949,538 \$	928,724	\$	830,101	\$	894,031	\$	1,057,545	\$ 11,030,695
ver)/Under Recovery - Month	\$	4,919	\$	(138,640) \$	(32,885) \$	(63,957) \$	157,960	\$	110,151 \$	(146,970)	\$	(7,863) \$	(104,656)	\$	9,964	\$	69,229	\$	10,897	
IMULATIVE (OVER)/UNDER RECOVERY																				
ginning Balance	\$	2,639,332	\$	2,649,797 \$	2,516,226 \$	2,488,620 \$	-,,		2,592,882 \$	-,,	\$	2,566,974 \$	2,564,492	\$	2,464,941	\$	2,480,738	\$	2,555,717	
ding Balance Before Interest erage Monthly Balance	<u>\$</u>	2,644,250	- \$	2,511,157 \$	2,483,341 \$	2,424,664 \$	2,587,615	5	2,703,032 \$	2,561,442	\$	2,559,111 \$	2,459,836	\$	2,474,904	<u> </u>	2,549,967	\$	2,566,614	
erage Monthly Balance erest Rate (1)	э	2,641,791 2.48%	3	2,580,477 \$ 2,48%	2,499,783 \$ 2.48%	2,456,642 \$ 2.48%	2,508,635 2,48%	\$	2,647,957 \$ 2.48%	2,634,927 2,48%	\$	2,563,043 \$ 2.48%	2,512,164 2.48%	\$	2,469,922 2,79%	\$	2,515,353 2,79%	\$	2,561,165	
mber of Days / Month		2.40%		2.40%	2.40%	2.46%	2.40%		2.46%	2.46%		2. 4 6% 31	2.46%		2.79%		2.79%		2.79% 31	366
mputed Interest	\$	5,547	\$	5,068 \$	5,279 \$	4,991 \$	5,267	\$	5,380 \$	5,532	\$	5,381 \$		\$	5,834	\$	5,750	\$		\$ 65,183
ding Balance with Interest	\$	2,649,797	\$	2,516,226 \$	2,488,620 \$	2,429,655 \$	2,592,882	\$	2,708,412 \$	2,566,974	\$	2,564,492 \$	2,464,941	\$	2,480,738	\$	2,555,717	\$	2,572,663	

Effective December 2002, includes credit for deferred income taxes, Prime rate * (1-t) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002.

nuary 2005 - February 2005	j	Jan-05 Estimated	Feb-05 (2) Estimated	Total
tal Costs (See page 5)	\$	1,159,985	\$ 1,107,121	\$ 2,267,106
)S Revenue (See page 7)	\$	1,130,697	\$ 1,079,042	\$ 2,209,739
DSRRA Revenue (See page 7)	\$		\$ · · · -	\$ -
tal Revenues (See page 7)	\$	1,130,697	\$ 1,079,042	\$ 2,209,739
ver)/Under Recovery - Month	\$	29,288	\$ 28,079	
JMULATIVE (OVER)/UNDER RECOVERY				
ginning Balance	\$	2,572,663	\$ 2,608,760	
ding Balance Before Interest	\$	2,601,951	\$ 2,636,839	
erage Monthly Balance	\$	2,587,307	\$ 2,622,800	
erest Rate (1)		3.10%	3.10%	
mber of Days / Month		31	28	365
imputed Interest	\$	6,809	\$ 6,234	\$ 13,043
ding Balance with Interest	\$	2,608,760	\$ 2,643,074	

Effective December 2002, includes credit for deferred income taxes, Prime rate * (1-t) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002. Standard Offer Service ends February 2005, all customers receive Default Service.

Calculation of the Standard Offer Service Revenue Reconciliation Adjustment ("SOSRRA") - Monthly Standard Offer Service Reconciliation Effective January 1, 2005

1 Indicated Reconciliation 2 2005 Beginning Balance 3 2005 Costs (Jan - Feb 2005) 4 2005 Computed Interest (Jan - Feb 2005) 5 Costs to be Recovered	\$ \$ \$	2,572,663 2,267,106 6,527 4,846,296
6 Less SOS Revenue (Jan - Feb 2005)	\$	2,209,739
7 Total Costs to be Recovered 8 Forecast 2005 kWh Sales (Jan - Feb 2005)	\$	2,636,558 43,328,212
9 Indicated SOSRRA	\$	0.06085
10 February 2005 Ending Balance 11	\$	36
12 Proposed Reconciliation		
13 Amount to Recover in SOSRRA	\$	-
14 Forecast 2005 kWh Sales (Jan - Feb 2005)		43,328,212
15 Proposed SOSRRA	\$	-
16 February 2005 Ending Balance	\$	2,643,074

Fitchburg Gas and Electric Light Company d/b/a Unitil Itemized Costs for Standard Offer Service Reconciliation	Jan-03 Actual	Feb-03 Actual	Mar-03 Actual	Apr-03 Actual	May-03 Actual	Jun-03 Actual	Jul-03 Actual	Aug-03 Actual	Sep-03 Actual	Oct-03 Actual	Nov-03 Actual	Dec-03 Actual	Total
Cost of Long Term Purchased Power Cost of Generation Unit Purchases							Hotau	Actual	Actual	Actual	Actual	Actual	•
Short Term Purchases and NEPEX (see detail below) Sales for Resale													
5 Cost of Constellation Power Source Contract	\$1,012,765	\$1,024,177	\$975,873	\$1,062,302	\$805,369	\$926,407	\$1,115,312	\$1,172,013	\$984,541	\$908,890	\$598,511	\$874,814	\$11,460,975
6 Renewable Energy Certificates	\$42,000	\$0	\$10,500	\$0	\$0	\$0	(\$10,500)	\$33,000	\$0	\$0	\$0	\$0	\$75,000
7 Working Capital (See page 6)	\$5,069	\$4,922	\$4,741	\$5,105	\$3,871	\$4,452	\$5,310	\$5,791	\$4,732	(\$3,486)	\$2,465	\$3,603	\$46,575
8 Bad Debt Costs (1)	<u>\$6,51</u> 7	\$6,516	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$6,517	\$78,201
9 Subtotal 10 LESS:	\$1,066,351	\$1,035,616	\$997,630	\$1,073,924	\$815,756	\$937,376	\$1,116,639	\$1,217,321	\$995,789	\$911,921	\$607,493	\$884,934	\$11,660,751
11 Cost Transfer to Default Service - Variable													
12 Total Costs	\$1,066,351	\$1,035,616	\$997,630	\$1,073,924	\$815,756	\$937,376	\$1,116,639	\$1,217,321	\$995,789	\$911.921	\$607,493	\$884,934	\$11,660,751
13									,			1,001	7,-50,101

(1) December 2002-December 2003 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25, totaling \$405,501 multiplied by test year allocation factor. Total SOS and DS allocation equals 34.72% with SOS equal to 19.285% and DS equal to 15.435%.

Bad Debt Expense from DTE 02-24/25 Bad Debt Allocation Factor Bad Debt Costs Allocated to SOS Monthly Bad Debt Cost Allocated to SOS

\$405,501 Tab D, Schedule MHC-7-8 (Electric) 19.285%

\$78,201 \$6,517

			·										
Fitchburg Gas and Electric Light Company d/b/a Unitil Itemized Costs for Standard Offer Service Reconciliation	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	Apr-04 Actual	May-04 Actual	Jun-04 Actual	Jul-04 Actual	Aug-04 Actual	Sep-04 Actual	Oct-04 Estimate	Nov-04 Estimate	Dec-04 Estimate	Total
1 Cost of Long Term Purchased Power			- 1000		Actual	Actour	Actual	Actual	Actual	Estillate	CStillate	Estimate	
2 Cost of Generation Unit Purchases													
3 Short Term Purchases and NEPEX (see detail below)													
4 Sales for Resale													
5 Cost of Constellation Power Source Contract	\$1,009,187	\$845,134	\$884,436	\$805,822	\$941,269	\$956,141	\$748.044	\$931,296	\$814,170	\$830,101	\$894.031	\$1,057,545	\$10,717,174
6 Renewable Energy Certificates	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$59,003	\$0	\$89,950
7 Working Capital (See page 6)	\$4,132	\$3,481	\$3,631	\$3,308	\$3,864	\$3,925	\$3,071	\$3,823	\$3,343	\$3,408	\$3,670	\$4,342	\$43,999
8 Bad Debt Costs (1)	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$6,556	\$78,667
9 Subtotal 10 LESS:	\$1,019,874	\$855,170	\$894,623	\$815,685	\$951,689	\$966,622	\$757,671	\$941,675	\$824,068	\$840,064	\$963,260	\$1,068,442	\$10,898,843
11 Cost Transfer to Default Service - Variable													
12 Total Costs	\$1,019,874	\$855,170	\$894,623	\$815,685	\$951,689	\$966,622	\$757,671	\$941,675	\$824,068	\$840,064	\$963,260	\$1,068,442	\$10,898,843

14 Note: Estimated Constellation Power Source Contract Costs from October 2004 through February 2005 assumed to be equal to SOS revenues on page 7.
(1) January 2004-December 2004 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25 multiplied by allocation factor of 19.40% filed in DTE 03-115.

Bad Debt Expense from DTE 02-24/25 Bad Debt Allocation Factor Bad Debt Costs Allocated to SOS

\$405,501 Tab D, Schedule MHC-7-8 (Electric)

19.40% SCHEDULE KMA-2, page 8 of 8, filed in DTE 03-115.

\$78,667

Monthly Bad Debt Cost Allocated to SOS

\$6,556

Fitchburg Gas and Electric Light Company d/b/a Unitil Itemized Costs for Standard Offer Service Reconciliation	Jan-05 Estimate	Feb-05 Estimate	Total
1 Cost of Long Term Purchased Power			
2 Cost of Generation Unit Purchases			
3 Short Term Purchases and NEPEX (see detail below)			
4 Sales for Resale			
5 Cost of Constellation Power Source Contract	\$1,130,697	\$1,079,042	\$2,209,739
6 Renewable Energy Certificates	\$21,855	\$20,858	\$89,950
7 Working Capital (See page 6)	\$4,642	\$4,430	\$9,072
8 Bad Debt Costs (1)	\$2,791	\$2,791	\$5,582
9 Subtotal	\$1,159,985	\$1,107,121	\$2,267,106
10 LESS:			
11 Cost Transfer to Default Service - Variable			
12 Total Costs	\$1,159,985	\$1,107,121	\$2,267,106

<sup>13
14</sup> Note: Estimated Constellation Power Source Contract Costs from October 2004 through February 2005 assumed to be equal to SOS revenues on page 7.
(1) January 2005-February 2005 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25 multiplied by allocation factor of 8.26% developed on SCHEDULE KMA-2, page 8 of 8.

Bad Debt Expense from DTE 02-24/25
Bad Debt Allocation Factor
Bad Debt Costs Allocated to SOS
Monthly Bad Debt Cost Allocated to SOS

405,501 Tab D, Schedule MHC-7-8 (Electric)
8,26% SCHEDULE KMA-2, page 8 of 8.

33,494
\$2,791

Fitchburg Gas and Electric Light Company d/b/a Unitil

Calculation of Working Capital for Standard Offer Service													00/12	DOLL KINA-2
Calculation of Working Capital for Standard Other Service														Page 6 of 8
	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
1 Cost of Constellation Power Source Contract	\$920,726	\$1,054,765	\$1,024,177	\$986,373	\$1,062,302	\$805,369	\$926,407	\$1,104,812	\$1,205,013	\$984,541	\$833.890	\$598.511	\$874.814	\$12.381.700
2 Number of Days of Lag / 365 (13.49/365)	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	3.70%	3.70%	3.70%	
3 Working Capital Requirement (L.1 * L.2)	\$39,705	\$45,485	\$44,166	\$42,536	\$45,810	\$34,730	\$39,950	\$47,643	\$51,964	\$42,457	\$30,820	\$22,120	\$32,332	\$519,717
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38,36%	38.36%	38.36%	38.36%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.14%	11.14%		11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	
8 Cost of Working Capital (L.3 * L.7)	\$4,422	\$5,069	\$4,922	\$4,741	\$5,105	\$3,871	\$4,452	\$5,310	\$5,791	\$4,732 (\$3,486) (1)	\$2,465	\$3,603	\$50,997

SCHEDULE KMA-2

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2. Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2002/2003 Federal and State combined tax rate.

(1) Includes adjustment of (\$6,869.77) for correction of number of days of lag calculated at 4.31% to 3.70%. In DTE 02-84 FG&E revised its working capital calculation in Exhibit FG&E-MHC-2. Line 1 was also adjusted to reflect cost of Constellation Power Source Contract, Renewable Energy Certificates were included in this line.

	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	Apr-04 Actual	May-04 Actual	Jun-04 Actual	Jul-04 Actual	Aug-04 Actual	Sep-04 Actual	Oct-04 Estimate	Nov-04 Estimate	Dec-04 Estimate	Total
1 Cost of Constellation Power Source Contract	\$1,009,187	\$845,134	\$884,436	\$805,822	\$941,269	\$956,141	\$748,044	\$931,296	\$814,170	\$830,101	\$894.031	\$1,057,545	\$10,717,174
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	3.70%	3.70%	3.70%	3,70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	*
3 Working Capital Requirement (L.1 * L.2)	\$37,298	\$31,235	\$32,688	\$29,782	\$34,788	\$35,338	\$27,647	\$34,420	\$30,091	\$30,680	\$33,042	\$39,086	\$396,095
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$4,143	\$3,470	\$3,631	\$3,308	\$3,864	\$3,925	\$3,071	\$3,823	\$3,343	\$3,408	\$3,670	\$4,342	\$43,999

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

	Jan-05 Estimate	Feb-05 Estimate	Total
1 Cost of Constellation Power Source Contract	\$1,130,697	\$1,079,042	\$2,209,739
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	
3 Working Capital Requirement (L.1 * L.2)	\$41,789	\$39,880	\$81,670
4 Cost of Equity	4.25%	4.25%	
5 Cost of Debt	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11,11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$4,642	\$4,430	\$9,072

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

Fitchburg Gas and Electric Light Company d/b/a Unitil Forecast of Standard Offer Service Revenues - Monthly Standard Offer Service Reconciliation October 2004 - December 2005

		Oct-04		Nov-04		Dec-04		Jan-05		Feb-05		Total (Jan-05 to Feb-05)
lard R-1	_											
kWh		489,104		7,897,711		9,561,552		,628,209		9,957,174		20,585,383
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		
Revenue	<u> \$ </u>	381,944	\$	402,783	\$	487,639	\$	542,039	\$	507,816	\$	1,049,855
Assistance R-2												
kWh				1 011 562		1 224 672	١,	264 202		075 044		0.000.007
Rate	\$	0.051	\$	1,011,562 0.051	\$	1,224,672 0.051		361,293, 0,051		1,275,344		2,636,637
Revenue	\$	0.051	- \$	51,590	<u>φ</u>	62,458	\$	69,426	\$	0.051 65,043	\$	134,468
revenue	<u> </u>		Ψ	31,330	Ψ	02,430	+	08,420	Ψ	00,043	Ψ.	134,400
Commercial G-1												
kWh		189.939		196,830		220,909		230,505		229,835		460,340
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0,051	\$	0.051		400,040
Revenue	\$	9.687	\$	10,038	\$	11,266	Š	11,756	\$	11,722	\$	23,477
					÷		Ť			,		
Commercial G-2												
kVVh	5	,335,303		5,528,858	(6,205,228	lε	3,474,765	•	6,455,945		12,930,710
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		,,
Revenue	\$	272,100	\$	281,972	\$	316,467	\$	330,213	\$	329,253	\$	659,466
trial G-3												
kWh		2,929,210		2,640,670		3,023,955		3,063,998		2,894,558		5,958,556
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		
Revenue	\$	149,390	\$	134,674	\$	154,222	\$	156,264	\$	147,622	\$	303,886
nal TOU G-4												
kWh		43,664		45,248		50,783		52,989		52,835		105,824
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		
Revenue	\$	2,227	\$	2,308	\$	2,590	\$	2,702	\$	2,695	\$	5,397
nd /or SH G-5												
kWh	_	38,559		39,958	_	44,846	١.	46,794		46,658		93,452
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		
Revenue	\$	1,967	\$	2,038	\$	2,287	\$	2,386	\$	2,380	\$	4,766
Iby Conice Cassiel Castro												
lby Service Special Contrac kWh	J.	40,419		17,169		5.639		20 202		15 5 4 4		40.000
Rate	\$	0.051	\$	0.051	\$	0.051	\$	28,392 0.051	\$	15,544 0.051		43,936
Revenue	\$	2.061	<u>\$</u>	876	\$	288	\$	1.448	\$	793	\$	2,241
***************************************	Ť	2,001	<u> </u>		¥	200	÷	1,440	<u> </u>	100	Ψ.	2,271
or Lighting S												
kWh		210,290		152,020		398,585		283,588		229,786		513,374
Rate	\$	0.051	\$	0.051	\$	0.051	\$	0.051	\$	0.051		310,374
Revenue	\$	10,725	\$	7,753	\$	20,328	ŝ	14,463	\$	11,719	\$	26,182
	Ť		Ť	7,1.00	Ť	20,020	Ť	11,100	*	11,110	*	20,102
Revenue	\$	830,101	\$	894,031	\$ 1	1,057,545	\$ 1	,130,697	\$ 1	1,079,042	\$	2,209,739
	—	200,101	*	20.,001	.*	.,50,,040	<u> </u>	,.00,001	Ψ	.,5,5,042	Ψ	2,200,100
lard Offer Service Revenue	Ren	onciliation	Ad	liustment R	eve	enues						
Total kWh		,276,488		7,530,026		0,736,169	22	170,533	21	1,157,679		43,328,212
Rate	\$		\$	-	\$	-	\$	-	\$	-		-0,0±0,a1&
Total Revenue		\$0		\$0	*	\$0	Ť	\$0	*	\$0		\$0
	_				-							

SCHEDULE KMA-2 Page 7 of 8

Fitchburg Gas & Electric Light Company d/b/a Unitil Monthly Electric Write Offs (Gross) - Electric Division Calendar Year 2003 Computation of Bad Debt Allocation Factor

SCHEDULE KMA-2 Page 8 of 8

			Standard Offer	
	Delivery	Default Service	Service	
<u>Month</u>	<u>Component</u>	<u>Component</u>	Component	<u>Total</u>
Jan-03	\$15,631	\$8,580	\$3,945	\$28,156
Feb-03	\$17,638	\$9,369	\$4,705	\$31,712
Mar-03	\$20,039	\$10,915	\$4,778	\$35,732
Apr-03	\$22,240	\$15,107	\$2,710	\$40,057
May-03	\$30,682	\$16,256	\$4,018	\$50,955
Jun-03	\$21,473	\$12,335	\$4,378	\$38,187
Jul-03	\$29,051	\$17,207	\$3,085	\$49,343
Aug-03	\$34,154	\$21,063	\$3,763	\$58,981
Sep-03	\$26,003	\$17,075	\$1,271	\$44,350
Oct-03	\$19,964	\$12,565	\$1,733	\$34,262
Nov-03	\$20,126	\$11,372	\$4,378	\$35,876
Dec-03	<u>\$50,497</u>	<u>\$30,007</u>	<u>\$5,308</u>	<u>\$85,813</u>
Total	\$307,499	\$181,852	\$44,073	\$533,423
Percentage	57.65%	34.09%	8.26%	100.00%

MONTHLY DEFAULT SERVICE RECONCILIATION

itchburg Gas and Electric Light Company d/b/a Unitil alculation of Default Service Deferral and Interest - Monthly Default Service Reconciliation anuary 2003 - December 2003

anuary 2003 - December 2003													
	Jan-03 <u>Actual</u>	Feb-03 <u>Actual</u>	Mar-03 <u>Actual</u>	Apr-03 <u>Actual</u>	May-03 <u>Actual</u>	Jun-03 <u>Actual</u>	Jul-03 <u>Actual</u>	Aug-03 <u>Actual</u>	Sep-03 <u>Actual</u>	Oct-03 <u>Actual</u>	Nov-03 Actual	Dec-03 <u>Actual</u>	Total
otal Costs (See page 3)	\$935,992	\$620,414	\$546,090	\$613,077	\$583,026	\$694,648	\$1,200,507	\$1,374,948	\$458,243	\$190,284	\$617,611	\$602,782	\$8,437,621
efault Service Revenues efault Service Adjustment Revenues	\$586,540 \$0	\$666,365 \$0	\$649,934 \$0	\$716,265 \$0	\$724,713 \$0	\$771,252 \$0	\$947,700 \$0	\$649,097 \$0	\$530,077 \$0	\$448,043 \$0	\$427,821 \$0	\$535,776 \$0	\$7,653,583 \$0
otal Revenues	\$586,540	\$666,365	\$649,934	\$716,265	\$724,713	\$771,252	\$947,700	\$649,097	\$530,077	\$448,043	\$427,821	\$535,776	\$7,653,583
Over)/Under Recovery - Month	\$349,451	(\$45,951)	(\$103,844)	(\$103,188)	(\$141,687)	(\$76,604)	\$252,807	\$725,851	(\$71,834)	(\$257,759)	\$189,790	\$67,006	\$784,038
<u>UMULATIVE (OVER)/UNDER RECOVERY</u> eginning Balance nding Balance Before Interest verage Monthly Balance	\$549,786 \$899,238 \$724,512	\$900,850 \$854,899 \$877,874	\$856,663 \$752,819 \$804,741	\$754,609 \$651,421 \$703,015	\$652,935 \$511,248 \$582,091	\$512,543 \$435,939 \$474,241	\$436,960 \$689,767 \$563,364	\$691,021 \$1,416,872 \$1,053,946	\$1,419,217 \$1,347,383 \$1,383,300	\$1,350,361 \$1,092,602	\$1,095,160 \$1,284,950	\$1,287,362 \$1,354,368	_
iterest Rate (1) umber of Days / Month	2.62% 31	2.62% 28	2.62%	2.62%	2.62% 31	2.62%	2.62% 31	2.62% 31	\$1,383,300 2.62% 30	\$1,221,482 2.47% 31	\$1,190,055 2.47% 30	\$1,320,865 2.47% 31	365
omputed Interest	\$1,612	\$1,764	\$1,791	\$1,514	\$1,295	\$1,021	\$1,253	\$2,345	\$2,978	\$2,558	\$2,412	\$2,766	\$23,309
nding Balance with Interest	\$900,850	\$856,663	\$754,609	\$652,935	\$512,543	\$436,960	\$691,021	\$1,419,217	\$1,350,361	\$1,095,160	\$1,287,362	\$1,357,134	

¹⁾ Includes credit for Deferred Income Taxes, prime rate * (1-t) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002.

anuary 2004 - December 2004	Jan-04 <u>Actual</u>	Feb-04 <u>Actual</u>	Mar-04 <u>Actual</u>	Apr-04 <u>Actual</u>	May-04 <u>Actual</u>	Jun-04 <u>Actual</u>	Jul-04 <u>Actual</u>	Aug-04 <u>Actual</u>	Sep-04 <u>Actual</u>	Oct-04 Estimated	Nov-04 Estimated	Dec-04 Estimated	Total
otal Costs (See page 4)	\$1,220,998	\$1,117,536	\$1,137,428	(\$138,651)	\$1,340,081	\$628,849	\$658,804	\$804,260	\$589,495	\$546,288	\$439,619	\$737,986	\$9,082,694
efault Service Revenues efault Service Adjustment Revenues	\$1,096,898 \$0	\$1,059,124 \$0	\$1,130,880 \$0	\$544,557 \$0	\$477,676 \$0	\$520,646 \$0	\$622,109 \$0	\$669,014 \$0	\$626,726 \$0	\$535,002 \$0	\$487,772 \$0	\$725,916 \$0	\$8,496,321 \$0
otal Revenues (See page 6)	\$1,096,898	\$1,059,124	\$1,130,880	\$544,557	\$477,676	\$520,646	\$622,109	\$669,014	\$626,726	\$535,002	\$487,772	\$725,916	\$8,496,321
)ver)/Under Recovery - Month	\$124,100	\$58,412	\$6,548	(\$683,208)	\$862,405	\$108,203	\$36,695	\$135,247	(\$37,231)	\$11,286	(\$48,153)	\$12,070	\$586,374
UMULATIVE (OVER)/UNDER RECOVERY													
eginning Balance	\$1,357,134	\$1,484,213	\$1,545,597	\$1,555,398	\$874,656	\$1,739,803	\$1,851,650	\$1.892.271	\$2.031.632	\$1,998,491	\$2,014,511	\$1,970,908	
nding Balance Before Interest	\$1,481,233	\$1,542,625	\$1,552,146	\$872,190	\$1,737,061	\$1,848,005	\$1,888,345	\$2,027,517	\$1,994,401	\$2,009,778	\$1,966,359	\$1,982,978	
verage Monthly Balance	\$1,419,183	\$1,513,419	\$1,548,872	\$1,213,794	\$1,305,858	\$1,793,904	\$1,869,998	\$1,959,894	\$2,013,017	\$2,004,134	\$1,990,435	\$1,976,943	-
terest Rate (1)	2.48%	2.48%	2.48%	2.48%	2.48%	2.48%	2.48%	2.48%	2.48%	2.79%	2.79%	2.79%	
umber of Days / Month	31	. 29	31	30	31	30	31	31	30	31	30	31	366
omputed Interest	\$2,980	\$2,972	\$3,252	\$2,466	\$2,742	\$3,645	\$3,926	\$4,115	\$4,090	\$4,734	\$4,550	\$4,669	\$44,141
nding Balance with Interest	\$1,484,213	\$1,545,597	\$1,555,398	\$874,656	\$1,739,803	\$1,851,650	\$1,892,271	\$2,031,632	\$1,998,491	\$2,014,511	\$1,970,908	\$1,987,648	

⁾ Includes credit for Deferred Income Taxes, prime rate * (1-1) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002.

	Jan-05 Estimated	Feb-05 <u>Estimated</u>	Mar-05 <u>Estimated</u>	Apr-05 <u>Estimated</u>	May-05 Estimated	Jun-05 <u>Estimated</u>	Jul-05 <u>Estimated</u>	Aug-05 Estimated	Sep-05 Estimated	Oct-05 Estimated	Nov-05 Estimated	Dec-05 Estimated	Total
otal Costs (See page 4)	\$802,759	\$768,855	\$2,279,277	\$2,227,288	\$1,996,929	\$2,233,461	\$2,518,855	\$2,477,843	\$2,358,218	\$2,075,679	\$2,113,661	\$2,484,282	\$24,337,108
efault Service Revenues efault Service Adjustment Revenues	\$778,418 \$0	\$745,082 \$0	\$2,228,606 \$0	\$2,177,488 \$0	\$1,950,905 \$0	\$2,183,632 \$0	\$2,464,269 \$0	\$2,423,906 \$0	\$2,306,336 \$0	\$2,028,344 \$0	\$2,065,637 \$0	\$2,430,242 \$0	\$23,782,864 \$0
otal Revenues (See page 6)	\$778,418	\$745,082	\$2,228,606	\$2,177,488	\$1,950,905	\$2,183,632	\$2,464,269	\$2,423,906	\$2,306,336	\$2,028,344	\$2,065,637	\$2,430,242	\$23,782,864
Over)/Under Recovery - Month	\$24,341	\$23,773	\$50,672	\$49,801	\$46,025	\$49,830	\$54,586	\$53,937 [°]	\$51,882	\$47,335	\$48,023	\$54,040	\$554,244
UMULATIVE (OVER)/UNDER RECOVERY eginning Balance nding Balance Before Interest verage Monthly Balance terest Rate (1)	\$1,987,648 \$2,011,989 \$1,999,818 3.10%	\$2,017,252 \$2,041,025 \$2,029,138 3.10%	\$2,045,848 \$2,096,520 \$2,071,184 3.10%	\$2,101,970 \$2,151,771 \$2,126,870 3.10%	\$2,157,187 \$2,203,212 \$2,180,200 3,10%	\$2,208,949 \$2,258,779 \$2,233,864 3.10%	\$2,264,468 \$2,319,054 \$2,291,761 3.10%	\$2,325,085 \$2,379,022 \$2,352,054 3,10%	\$2,385,212 \$2,437,094 \$2,411,153 3,10%	\$2,443,235 \$2,490,569 \$2,466,902 3,10%	\$2,497,061 \$2,545,084 \$2,521,073 3,10%	\$2,551,505 \$2,605,545 \$2,578,525 3,10%	-
umber of Days / Month	31	28	31	30	31	30	31	31	30	31	30	31	365
omputed Interest	\$5,263	\$4,823	\$5,451	\$5,417	\$5,737	\$5,689	\$6,031	\$6,190	\$6,141	\$6,492	\$6,420	\$6,786	\$70,439
nding Balance with Interest	\$2,017,252	\$2,045,848	\$2,101,970	\$2,157,187	\$2,208,949	\$2,264,468	\$2,325,085	\$2,385,212	\$2,443,235	\$2,497,061	\$2.551.505	\$2 612 330	

) Includes credit for Deferred Income Taxes, prime rate * (1-t) where t = combined state and federal income tax rate in compliance with DTE Order in 02-24/25 issued December 2, 2002.

Fitchburg Gas and Electric Light Company d/b/a Unitil Itemized Costs for Default Service Reconciliation - Monthly Defau	ilt Service Reco	nciliation										00.	Page 3 of 7
No. 11 - 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1 - 1	Jan-03 <u>Actual</u>	Feb-03 Actual	Mar-03 <u>Actual</u>	Apr-03 Actual	May-03 <u>Actual</u>	Jun-03 <u>Actual</u>	Jul-03 <u>Actual</u>	Aug-03 <u>Actual</u>	Sep-03 <u>Actual</u>	Oct-03 <u>Actual</u>	Nov-03 <u>Actual</u>	Dec-03 <u>Actual</u>	Total
1 DS-Variable kWh Sales 2 Market Proxy Rate 3 Calculated DS-Variable Costs - Transfer from Standard Offer 4 5 Cost of Long Term Purchased Power 6 Cost of Generation Unit Purchases 7 Short Term Purchases and NEPEX 8 Sales for Resale (1) 9 DS Supplier Costs 10 Working Capital (2) 11 Bad Debt Costs (3) 12 Renewable Energy Certificates (4) 13 Total Costs	\$926,324 \$4,452 \$5,216 \$935,992	(\$13,261) \$625,515 \$2,943 \$5,218	\$538,289 \$2,587 \$5,214 \$546,090	\$604,954 \$2,907 \$5,216 \$613,077	\$575,047 \$2,764 \$5,216 \$583,026	\$686,135 \$3,298 \$5,216 \$694,648	\$1,189,574 \$5,717 \$5,216 \$1,200,507	\$1,363,181 \$6,551 \$5,216 \$1,374,948	\$450,861 \$2,167 \$5,216 \$458,243	\$189,470 (\$4,402) \$5,216 \$190,284	\$609,883 \$2,512 \$5,216 \$617,611	\$595,115 \$2,451 \$5,216 \$0 \$602,782	\$8,354,346 \$33,947 \$62,589 \$0 \$8,437,621

(1) Additional charges related to purchase of capacity to service Default load in 2000. Billed in 2002 as a result of ISO-NE's settlement of the ICAP market.

(2) See Page 5.

(3) December 2002-December 2003 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25, totaling \$405,501 multiplied by test year allocation factor. Total SOS and DS allocation equals 34.72% with SOS equal to 19.285% and DS equal to 15.435%.

Bad Debt Expense from DTE 02-24/25

\$405,501 Tab D, Schedule MHC-7-8 (Electric)

Bad Debt Allocation Factor Bad Debt Costs Allocated to DS Monthly Bad Debt Cost Allocated to DS 15.435% \$62,589 \$5,216

(4) Prior to December 1, 2003 the Default Service Supplier was responsible for purchasing Renewable Energy Certificates.

Fitchburg Gas and Electric Light Company d/b/a Unitil Itemized Costs for Default Service Reconciliation - Monthly Defa	ult Service Reco	onciliation											
	Jan-04 <u>Actual</u>	Feb-04 <u>Actual</u>	Mar-04 <u>Actual</u>	Apr-04 <u>Actual</u>	May-04 <u>Actual</u>	Jun-04 <u>Actual</u>	Jul-04 <u>Actual</u>	Aug-04 <u>Actual</u>	Sep-04 <u>Actual</u>	Oct-04 Estimate	Nov-04 Estimate	Dec-04 Estimate	Total
DS-Variable kWh Sales Market Proxy Rate Calculated DS-Variable Costs - Transfer from Standard Offer Cost of Long Term Purchased Power Cost of Generation Unit Purchases Short Term Purchases and NEPEX Sales for Resale DS Supplier Costs Working Capital (1) Bad Debt Costs (2) Renewable Energy Certificates (3) Total Costs	\$1,206,966 \$4,942 \$9,090 \$0	\$1,061,983 \$4,546 \$9,090 \$41,918	\$1,123,725 \$4,613 \$9,090 \$0	(\$147,137) (\$604) \$9,090 \$0	\$1,325,549 \$5,442 \$9,090 \$0	\$617,225 \$2,534 \$9,090 \$0	\$598,097 \$2,656 \$9,090 \$48,960	\$791,919 \$3,251 \$9,090 \$0	\$578,032 \$2,373 \$9,090 \$0	\$535,002 \$2,196 \$9,090 \$0	\$487,772 \$1,760 \$9,090 (\$59,003)	\$725,916 \$2,980 \$9,090 \$0	\$8,905,050 \$36,690 \$109,080 \$31,875
13 Total Costs	\$1,220,998	\$1,117,536	\$1,137,428	(\$138,651)	\$1,340,081	\$628,849	\$658,804	\$804,260	\$589,495	\$546,288	\$439,619	\$737,986	\$9,082,694

Note: Estimated DS Supplier Costs from October 2004 through December 2005 assumed to be equal to forecast revenue on page 6.

(1) See Page 5.

(2) January 2004-December 2004 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25, multiplied by allocation factor of 26.90% filed in DTE 03-115.

Bad Debt Expense from DTE 02-24/25

\$405,501 Tab D, Schedule MHC-7-8 (Electric)

Bad Debt Allocation Factor

26.90% SCHEDULE KMA-3, page 7 of 7, filed in DTE 03-115.

Bad Debt Costs Allocated to DS

\$109,080 \$9,090

Monthly Bad Debt Cost Allocated to DS

⁽³⁾ Prior to December 1, 2003 the Default Service Supplier was responsible for purchasing Renewable Energy Certificates.

SCHEDULE	KMA-3	
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Fitchburg Gas and Electric Light Company d/b/a Unitil												SCH	HEDULE KMA-3 Page 4 of 7
Itemized Costs for Default Service Reconciliation - Monthly Defau			N 05	405	M 05								
	Jan-05 <u>Estimate</u>	Feb-05 Estimate	Mar-05 Estimate	Apr-05 Estimate	May-05 <u>Estimate</u>	Jun-05 Estimate	Jul-05 <u>Estimate</u>	Aug-05 Estimate	Sep-05 <u>Estimate</u>	Oct-05 Estimate	Nov-05 <u>Estimate</u>	Dec-05 Estimate	Total
1 DS-Variable kWh Sales													
2 Market Proxy Rate													
3 Calculated DS-Variable Costs - Transfer from Standard Offer													
4													
5 Cost of Long Term Purchased Power													
6 Cost of Generation Unit Purchases													
7 Short Term Purchases and NEPEX													
8 Sales for Resale													
9 DS Supplier Costs	\$778,418	\$745,082	\$2,228,606	\$2,177,488	\$1,950,905	\$2,183,632	\$2,464,269	\$2,423,906	\$2,306,336	\$2,028,344	\$2,065,637	\$2,430,242	\$23,782,864
10 Working Capital (1)	\$3,235	\$3,096	\$9,261	\$9,048	\$8,106	\$9,073	\$10,240	\$10,073	\$9,583	\$8,428	\$8,584	\$10,099	\$98,827
11 Bad Debt Costs (2)	\$11,520	\$11,520	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$14,311	\$166,147
12 Renewable Energy Certificates (3)	\$9,586	\$9,157	\$27,100	\$26,442	\$23,608	\$26,446	\$30,035	\$29,554	\$27,988	\$24,596	\$25,129	\$29,630	\$289,270
13 Total Costs	\$802,759	\$768,855	\$2,279,277	\$2,227,288	\$1,996,929	\$2,233,461	\$2,518,855	\$2,477,843	\$2,358,218	\$2,075,679	\$2,113,661	\$2,484,282	\$24,337,108

Note: Estimated DS Supplier Costs from October 2004 through December 2005 assumed to be equal to forecast revenue on page 6.

^(?) January 2005-December 2005 bad debt expense determined using test year bad debt costs, per December 2, 2002 Department Order in DTE 02-24/25, multiplied by allocation factor developed on SCHEDULE KMA-3, page 7 of 7.

	Jan - Feb 05	Mar - Dec 05	
Bad Debt Expense from DTE 02-24/25	\$405,501	\$405,501	Tab D, Schedule MHC-7-8 (Electric)
Bad Debt Allocation Factor	34.09%	42.35%	SCHEDULE KMA-3, page 7 of 7
Bad Debt Costs Allocated to DS	\$138,235	\$171,730	
Monthly Bad Debt Cost Allocated to DS	\$11.520	\$14 311	

⁽³⁾ Prior to December 1, 2003 the Default Service Supplier was responsible for purchasing Renewable Energy Certificates.

⁽¹⁾ See Page 5.

Fitchburg Gas and Electric Light Company d/b/a Unitil Calculation of Cash Working Capital for Default Service

SCHEDULE KMA-3 Page 5 of 7

	Dec-02 Actual	Jan-03 Actual	Feb-03 Actual	Mar-03 Actual	Apr-03 Actual	May-03 Actual	Jun-03 Actual	Jul-03 Actual	Aug-03 Actual	Sep-03 Actual	Oct-03 Actual	Nov-03 Actual	Dec-03 Actual	Total
1 DS Supplier Costs including Renewable Energy Certificates	583,454	\$926,324	\$612,254	\$538,289	\$604,954	\$575,047	\$686,135	\$1,189,574	\$1,363,181	\$450.861	\$189,470	\$609.883	\$595,115	\$8,924,538
2 Number of Days of Lag / 365 (13.49/365)	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	3.70%	3.70%	3.70%	*-,
3 Working Capital Requirement (L.1 * L.2)	\$25,160	\$39,946	\$26,402	\$23,213	\$26,088	\$24,798	\$29,588	\$51,298	\$58,785	\$19,443	\$7,003	\$22,541	\$21,995	\$376,259
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	, ,
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	
8 Cost of Working Capital (L.3 * L.7)	\$2,804	\$4,452	\$2,943	\$2,587	\$2,907	\$2,764	\$3,298	\$5,717	\$6,551	\$2,167	(\$4,402) (1)	\$2,512	\$2,451	\$36,751

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2. Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2002/2003 Federal and State combined tax rate.

(1) Includes adjustment of (\$5,182.36) for correction of number of days of lag calculated at 4.31%. In DTE 02-84 FG&E revised its working capital calculation in Exhibit FG&E-MHC-2.

	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	Apr-04 Actual	May-04 Actual	Jun-04 Actual	Jul-04 Actual	Aug-04 Actual	Sep-04 Actual	Oct-04 Estimate	Nov-04 Estimate	Dec-04 Estimate	Total
1 DS Supplier Costs including Renewable Energy Certificates	1,206,966	1,103,901	1,123,725	(147, 137)	1,325,549	617,225	647,057	791,919	578,032	535,002	428,769	725,916	\$8,936,924
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
3 Working Capital Requirement (L.1 * L.2)	\$44,608	\$40,799	\$41,532	(\$5,438)	\$48,991	\$22,812	\$23,915	\$29,268	\$21,363	\$19,773	\$15.847	\$26,829	\$330,299
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	*,
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$4,955	\$4,532	\$4,613	(\$604)	\$5,442	\$2,534	\$2,656	\$3,251	\$2,373	\$2,196	\$1,760	\$2,980	\$36,690

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

	Jan-05 Estimate	Feb-05 Estimate	Mar-05 Estimate	Apr-05 Estimate	May-05 Estimate	Jun-05 Estimate	Jul-05 Estimate	Aug-05 Estimate	Sep-05 Estimate	Oct-05 Estimate	Nov-05 Estimate	Dec-05 Estimate	Total
1 DS Supplier Costs including Renewable Energy Certificates	788,004	754,239	2,255,706	2.203.930	1.974.512	2.210.077	2,494,304	2,453,460	2.334.324	2.052.940	2,090,766	2.459.873	\$24.072.134
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	42 1,01 2,101
3 Working Capital Requirement (L.1 * L.2)	\$29,124	\$27,876	\$83,368	\$81,455	\$72.976	\$81,682	\$92.187	\$90,677	\$86,274	\$75,874	\$77.272	\$90.914	\$889,680
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4000,000
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.11%	11.11%	11.11%	11.11%	11.11%		11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$3,235	\$3,096	\$9,261	\$9,048	\$8,106	\$9,073	\$10,240	\$10,073	\$9,583	\$8,428	\$8,584	\$10,099	\$98.827

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

		Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total (Jan-05 to Dec-05)
ard R-1	kWh Rate		\$ 0.06186		5,682,912 \$ 0.07409	\$ 0.07409	\$ 0.07409	\$ 0.07409	\$ 0.07409	12,520,402 \$ 0.07409	\$ 0.07409	14,971,599 \$ 0.07409	\$ 0.07409	11,813,132 \$ 0.07409	12,446,612 \$ 0.07409	15,021,367 \$ 0.07409	143,812,278
	Revenue	\$ 247,714	\$ 261,229	\$ 378,790	\$ 421,047	\$ 394,463	\$ 991,524	\$ 953,511	\$ 821,760	\$ 927,637	\$1,122,398	\$ 1,109,246	\$ 1,003,127	\$ 875,235		\$1,112,933	\$ 10,655,052
ssistance R-2																	
	kWh Rate		\$ 0.06186		\$ 0.07409						1,264,315 \$ 0.07409			985,900 \$ 0.07409			11,083,655
	Revenue	\$ 59,338	3 -	\$ -	\$ -	\$ -	\$ 82,751	\$ 79,578	\$ 68,582	\$ 77,419	\$ 93,673	\$ 92,575	\$ 83,719	\$ 73,045	\$ 76,962	\$ 92,883	\$ 821,188
Commercial G-1																	
	kWh Rate	174,347 \$ 0.06198	180,672 \$ 0.06198	202,774 \$ 0.07423	211,582 \$ 0.07423	210,967 \$ 0.07423	407,369 \$ 0.07423	406,838 \$ 0.07423	370,174 \$ 0.07423	420,237 \$ 0.07423	461,068 \$ 0.07423	445,351 \$ 0.07423	445,812 \$ 0.07423	374,682 \$ 0.07423	388,201 \$ 0.07423	435,420 \$ 0.07423	4,577,701
	Revenue	\$ 10,806	\$ 11,198	\$ 15,052	\$ 15,706					\$ 31,194		\$ 33,058		\$ 27,813	\$ 28,816		\$ 339,803
Commercial G-2																	
	kWh Rate	2,227,093	2,307,888 \$ 0.06666	2,590,222	2,702,733 \$ 0.09019	2,694,878	8,274,695	8,263,906	7,519,171	8,536,075	9,365,456	9,046,189	9,055,555	7,610,725	7,885,339	8,844,471	89,799,193
	Revenue				\$ 243,759		\$ 0.09019 \$ 746,295							\$ 0.09019 \$ 686,411	\$ 0.09019 \$ 711,179		\$ 8,098,989
						.:											
rial G-3																	
	kWh Rate	1,021,881	921,222 \$ 0.06478	1,054,934	1,068,903	1,009,792	3,932,367	3,856,387	3,727,883	4,003,578	3,904,057	3,870,837	3,746,363	3,801,991	3,442,885	3,924,739	40,289,782
	Revenue				\$ 0.08736 \$ 93,379		\$ 0.08736 \$ 343,532							\$ 0.08736 \$ 332,142		\$ 0.08736 \$ 342.865	\$ 3,519,715
													<u> </u>				- STORY OF THE STO
ial TOU G-4																	
	kWh	-	-		-		48,828	48,764	44,370	50,370	55,264	53,381	53,436	44,910	46,530	52,190	498,043
	Rate Revenue	\$ 0.06666			\$ 0.09019		\$ 0.09019	\$ 0.09019 \$ 4,398	\$ 0.09019 \$ 4,002		\$ 0.09019 \$ 4,984	\$ 0,09019 \$ 4,814			\$ 0.09019 \$ 4,197		\$ 44,918
														·	- 1112	,,,,,	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,
nd /or SH G-5																	
	kWh	1,198	1,242	1,394	1,454	1,450	44,459	44,401	40,400	45,864	50,320	48,605	48,655	40,892	42,367	47,521	456,388
	Rate Revenue		\$ 0.06666 \$ 83		\$ 0.09019 \$ 131		\$ 0.09019 \$ 4.010		\$ 0.09019 \$ 3,644			\$ 0.09019 \$ 4,384			\$ 0.09019 \$ 3,821	\$ 0.09019 \$ 4,286	\$ 41,162
															<u> </u>	+ 1,200	11,102
by Service Special Contract	kWh		-		_		20,310	707	33,917	10,437	5,695	51,172	108,678	40,823	17,341	5,695	294,775
	Rate	<u>\$</u> -	\$ -	<u>\$</u>			\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	\$ 0.09019	
	Revenue		\$ -	\$ -	\$ -	\$ -	\$ 1,832	\$ 64	\$ 3,059	\$ 941	\$ 514	\$ 4,615	\$ 9,802	\$ 3,682	\$ 1,564	\$ 514	\$ 26,586
or Lighting S																	
	kWh Rate	36,134 \$ 0.06666	26,122 \$ 0.06666	68,489 \$ 0,09019	48,729 \$ 0.09019	39,484 \$ 0,09019	266,329 \$ 0.09019	260,749	205,764 \$ 0.09019	201,135	201,878 \$ 0,09019	234,851	259,285	247,008 \$ 0.09019	179,162	466,243	2,610,617
	Revenue	\$ 2,409											\$ 23,385				\$ 235,452
Revenues		\$ 535,002	\$ 487 772	\$ 725.916	\$ 778.418	\$ 745.092	\$2 229 808	\$2 177 499	\$1 050 005	£2 402 622	\$2.464.260	\$ 2,423,906	£ 2 200 220	62 020 244	\$2.00F.007	#D 400 040	Ø 90 700 004
		8,424,310	7,660,058	9,030,382	9,716,313	9,280,680	27,493,951	26,825,461	23,958,722	26,833,025	30,457,175	29,971,484		24,960,063			\$ 23,782,864 293,422,432
t Conico Adiustment P	- Data Effective (-	4 0007							 						,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	11	
It Service Adjustment Revenue: It Service Adjustment kWh	s, Nate Effective Jar		41,332,498	46,335,899	48,542,512	46,430,728	45,155,191	44.882.931	41.541.478	45.486.956	47,619,144	47,468,081	45.777.516	42,414,412	42 674 915	47 741 646	545,735,510
		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
lues		<u> , </u>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	<u> </u>	\$ -	<u> </u>	\$ -	\$ -	\$ -	\$ -	\$ -

Fitchburg Gas & Electric Light Company d/b/a Unitil Monthly Electric Write Offs (Gross) - Electric Division Calendar Year 2003 Computation of Bad Debt Allocation Factor

SCHEDULE KMA-3 Page 7 of 7

			Standard Offer	
	Delivery	Default Service	Service	
<u>Month</u>	Component	Component	Component	<u>Total</u>
Jan-03	\$15,631	\$8,580	\$3,945	\$ 28,15 6
Feb-03	\$17,638	\$9,369	\$4,705	\$31,712
Mar-03	\$20,039	\$10,915	\$4,778	\$35,732
Apr-03	\$22,240	\$15,107	\$2,710	\$40,057
May-03	\$30,682	\$16,256	\$4,018	\$50,955
Jun-03	\$21,473	\$12,335	\$4,378	\$38,187
Jul-03	\$29,051	\$17,207	\$3,085	\$49,343
Aug-03	\$34,154	\$21,063	\$3,763	\$58,981
Sep-03	\$26,003	\$17,075	\$1,271	\$44,350
Oct-03	\$19,964	\$12,565	\$1,733	\$34,262
Nov-03	\$20,126	\$11,372	\$4,378	\$35,876
Dec-03	<u>\$50,497</u>	\$30,007	<u>\$5,308</u>	<u>\$85,813</u>
Total	\$307,499	\$181,852	\$44,073	\$533,423
Percentage	57.65%	34.09%	8.26%	100.00%

MONTHLY EXTERNAL TRANSMISSION CHARGE RECONCILIATION

Column C					itchburg Gas and Electric							SC	HEDULE KMA-4			
Line	L				fonthly External Transmis	sion Charge R	teconciliation						Page 1 of 7			
Line ADMINISTRATIVE COMPREHENSIVE COMP	L				200	03			,							
Line ADMINISTRATIVE COMPREHENSIVE COMP																
Line ADMINISTRATIVE COMPREHENSIVE COMP																
Line Month COSTS (1) TANAINSISSION (2) COSTS (2) TANAINSISSION (2) COSTS (3) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (3) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (3) TANAINSISSION (2) COSTS (4) TANAINSISSION (2) COSTS (3) TANAINSISSION (2) COSTS (4) TANAINS											MAINE	<u> </u>				
Line ADMINISTRATIVE COMPREHENSIVE ADMINISTRATIVE CONGESTION CONGESTION CONGESTION CONGESTION CONGESTION COSTS (1) TRANSMISSION (2) COSTS (1) COSTS				ISO	NEP	NEPOOL			OVER-	NEP	ELECTRIC (New	COST OF	Total External			
# Month	Line			ADMINISTRATIVE	COMPREHENSIVE	RN/TRANS.	CONGESTION	CONGESTION	DESIGNATION				Transmission			
Col. A Col. B Col. Col. D Col. E Col. F Col. G Col. H Col. Col. D	#	Month		COSTS (1)	TRANSMISSION (2)	COSTS	PURCHASES (3)	SALES								
Jan				Col. A												
2 Feb										001. 0	301.11	001.1				
2 Feb	1	Jan	Act	\$ (848)	\$ (56.614)	\$ 152 449	\$ 396	\$ -	\$ -	\$ -	· ·	\$ 458	\$ 95.842			
3 Mar	_								 '	_	.t '					
4 Apr									<u> </u>		T					
5 May									,							
S Jun					¢ (10,007)	¢ 102,073	¢ 41,000									
7 Jul					¢ (18.141)	Φ 120,271 Φ 145 565	(3,072)		*							
8 Aug Act \$ (1,856) \$ 11,076 \$ 133,755 \$ 38,372 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$									*		· · · · · · · · · · · · · · · · · · ·					
9 Sep Act \$ (1.659) \$ (10.366) \$ (44.491) \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$									T . T			· · · · · · · · · · · · · · · · · · ·				
10																
11 Nov						\$ (44,491)	\$ -	<u> </u>								
12 Dec Act \$ (61) \$ 9,272 \$ 138,949 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$																
13 14 15 Total 2003 Costs \$ (7,743) \$ (74,141) \$ 1,635,741 \$ 165,601 \$ - \$ - \$ - \$ - \$ \$ \$ 6,982 \$ 1,72 16 16 17 Less: 2003 External Transmission Revenue \$1,79 18 19 2003 (Over)/under Recovery \$ \$ \$ (60) 20 21 (Over)/under Recovery - Beg. of Year \$21 22 23 Computed Interest (See page 4) \$ \$ (21) 25 (Over)/under Recovery - End of Year \$ (11) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates \$ (21) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE \$ (3) Costs since the Implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. \$ (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator (TSOT), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the tability for the transmission system.																
14		Dec	Act	\$ (61)	\$ 9,272	\$ 138,949	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 610	\$ 148,770			
15 Total 2003 Costs \$ (7,743) \$ (74,141) \$ 1,635,741 \$ 165,601 \$ - \$ - \$ - \$ - \$ 6,962 \$ 1,72 16		13														
16 State S	13															
17 Less: 2003 External Transmission Revenue \$1,79 18 19 2003 (Over)/under Recovery		14														
18 2003 (Over)/under Recovery Seg. of Year \$21 (Over)/under Recovery - Beg. of Year \$21 (Over)/under Recovery - Beg. of Year \$21 (Over)/under Recovery - Beg. of Year \$22 (Computed Interest (See page 4) \$23 (Computed Interest (See page 4) \$25 (Over)/under Recovery - End of Year \$25 (Over)/under Recovery - End of Year \$25 (Over)/under Recovery - End of Year \$26 (Over)/under Recovery - End of Year \$27 (Over)/under Recovery - End of Year \$28 (Over)/under Recovery - En																
19 2003 (Over)/under Recovery S (6 20 S (10 Ver)/under Recovery - Beg. of Year S (21 (Over)/under Recovery - Beg. of Year S (21 (22 S (22 S (24		Less: 2003 External	Transmi	ission Revenue									\$1,796,369			
20 (Over)/under Recovery - Beg. of Year \$21 22 Computed Interest (See page 4) \$25 25 (Over)/under Recovery - End of Year \$3 26 (Over)/under Recovery - End of Year \$3 27 (1) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.																
221 (Over)/under Recovery - Beg. of Year \$21 22		2003 (Over)/under R	Recovery	<u> </u>									\$ (69,930)			
22 Computed Interest (See page 4) 24 (25 (Over)/under Recovery - End of Year 25 (Over)/under Recovery - End of Year 26 (1) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billied for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.			1													
23 Computed Interest (See page 4) 25 (Over)/under Recovery - End of Year 25 (Over)/under Recovery - End of Year 26 (Over)/under Recovery - End of Year 27 (1) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover 28 incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited 29 to the ETC since all ISO costs were excluded in the determination of distribution rates. 20 Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both 20 PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE 20 is typically a small credit or charge. 21 (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. 22 Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. 23 (4) See Page 6. 24 (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		(Over)/under Recove	ery - Beg	g. of Year									\$213,674			
24 25 (Over)/under Recovery - End of Year \$ 15																
(1) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		Computed Interest (See pag	e 4)								1	9,087			
(1) Line relabeled from ISO Expenses EFC to ISO Administrative Costs. The Electric Fuel Charge (EFC) account was set up to recover incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.																
incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.	25	(Over)/under Recove	ery - End	of Year									\$ 152,832			
incremental costs through the EFC. Effective October 2001, all ISO Administrative costs are charged/credited to the ETC since all ISO costs were excluded in the determination of distribution rates. (2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.																
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(2) Effective March 2003, FG&E is billed for NEP's PTF facilities only. Prior to that, comprehensive transmission service covered both PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		incremental costs the	rough the	e EFC. Effective Oct	ober 2001, all ISO Adminis	strative costs a	are charged/credited									
PTF and Non-PTF facilities. Since NEP's PTF costs are offset by revenues it receives under the NEPOOL OATT, the bill to FGE is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		to the ETC since all	ISO cos	sts were excluded in	he determination of distrib	ution rates.										
is typically a small credit or charge. (3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.									both	·						
(3) Costs since the implementation of locational marginal pricing in March 2003 reflect billings related to prior periods. Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.					sts are offset by revenues	it receives und	der the NEPOOL OAT	Γ, the bill to FGE								
Also, FG&E has not incurred Reliability Must-Run Payments post March 2003. (4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.																
(4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		(3) Costs since the in	mplemer	ntation of locational m	arginal pricing in March 2	003 reflect bill	ings related to prior pe	riods.								
(4) See Page 6. (5) Pursuant to FG&E Tariff, M.D.T.E. No. 97, includes costs billed to FG&E by any other transmission provider, and by regional transmission or operating entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		Also, FG&E has not	incurred	Reliability Must-Run	Payments post March 20	03.	i									
entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		(4) See Page 6.														
entities such as NEPOOL, a regional transmission group, an independent system operator ("ISO"), or any other regional body, in the event that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.		(5) Pursuant to FG&	E Tariff,	M.D.T.E. No. 97, inc	ludes costs billed to FG&E	by any other	transmission provider.	and by regional	transmission or o	perating						
that they are authorized to bill FG&E directly for their services and shall include any other charges relating to the stability of the transmission system.	i	entities such as NEP	200L, a	regional transmission	group, an independent s	ystem operato	or ("ISO"), or any other	regional body, in	the event							
Effective December 1, 2002, the ETC shall also include working capital costs.		that they are authorize	zed to bi	II FG&E directly for the	neir services and shall incl	ude any other	charges relating to the	stability of the tr	ansmission syste	m.						
		Effective December	1, 2002,	the ETC shall also in	clude working capital cost	s.			T							
			1		1				-							

	•			Fitchburg Gas and Electric	c Light Compa	any d/b/a Unitil				<u> </u>	SCHI	EDULE KMA-4		
				Monthly External Transmi	ssion Charge	Reconciliation						Page 2 of 7		
				Foreca	st 2004	·····					T			
														
										MAINE				
			ISO	NEP	NEPOOL		!	OVER-		ELECTRIC (New	COST OF	Total Externa		
Line			ADMINISTRATIVE	COMPREHENSIVE	RN/TRANS.	CONGESTION	CONGESTION	DESIGNATION	NEP TRANS	Brunswick	WORKING	Transmission		
#	Month		COSTS (1)		COSTS	PURCHASES (3)		SALES	CREDIT	Power)	CAPITAL (4)	Costs (5)		
			Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Coi. J		
									555		00			
1	Jan	Act	\$ (2,041)	\$ 59.756	\$ 154,050	s -	\$ -	\$ -	\$ -	\$ -	\$ 867	\$ 212,631		
	Feb	Act	\$ 2,032		\$ (11,446)		\$ -	\$ -	\$ -	<u> </u>	\$ 139	\$ 33,486		
	Mar	Act	\$ (400)		\$ 139,943		·			<u> </u>	\$ 618			
	Apr	Act	\$ (411)	\$ (15.726)	\$ 209,609	\$ -		-	\$ -		\$ 794	\$ 194,266		
	May	Act	\$ (177)	\$ -		\$ -	 	<u> </u>	<u> </u>	\$ -	 	\$ 246,967		
	Jun	Act	\$ 1,097				<u> </u>	\$ -		\$ -	\$ 990	\$ (4,810)		
	Jul	Act	\$ 1,434		\$ 136,940	\$ -	 ' 	\$ -	<u> </u>	\$ -	+	\$ 152,716		
	Aug	Act	\$ 1,516		\$ 200,837		+	+ :		\$ -				
	Sep	Act	\$ 2,023		\$ 133,474			\$ -		\$ -		\$ 115,985		
	Oct	Est	\$ 1,000		\$ 133,054			\$ -	<u> </u>	<u>'</u>	\$ 559			
	Nov	Est	\$ 1,000		\$ 141,516				 	\$ -		\$ 145,109		
							1 '	*						
12 Dec Est \$ 1,000 \$ 2,000 \$ 156,157 \$ - \$ - \$ - \$ - \$ 653 \$ 15														
14														
	Total Forecast 2004	Costs	\$ 8,073	\$ 101.572	\$1,631,439	\$ (1,029)	\$ -	\$ -	\$ -	\$ -	\$ 7,144	\$ 1,747,199		
16	10.0.1.0.0000.2001.	000.0	0,010	101,012	₩ 1,001,-100	(1,020)	1	Ψ	<u> </u>	Ψ -	7,144	Ψ 1,747,100		
	Less: 2004 External	Transmi	ssion Revenue				 					\$ 1,632,998		
18		110110111	00.0171.010.1100									\$ 1,002,000		
	2004 (Over)/under Ro	ecoverv				· · · · · · · · · · · · · · · · · · ·						\$ 114,201		
20	2007 (0101)/411001111	0001017										Ψ 114,201		
	(Over)/under Recove	rv - Ren	of Year	<u> </u>						 		\$ 152,832		
22	(0.101)/411001 1100010	, Dog	. 01 1 001					 				Ψ 102,002		
	Computed Interest (S	ee page	= 4)									\$ 8,563		
24	Compared interest (C	oo pag.	· · · · · · · · · · · · · · · · · · ·								 	Ψ 0,505		
	(Over)/under Recove	rv - End	of Year			-		 			-	\$ 275,596		
	(.,										2,0,000		
						· ·						-		
	(1) Line relabeled from	n ISO E	xpenses EFC to ISC	Administrative Costs. TI	he Electric Fu	el Charge (EFC) ac	count was set un	to recover						
	incremental costs thr	ough the	EFC. Effective Octo	ber 2001, all ISO Admini	strative costs	are charged/credite	d	1				-		
				he determination of distrib		302.0.0410				1				
				PTF facilities only. Prior		rehensive transmiss	sion service cover	ed both						
	PTF and Non-PTF fa	cilities.	Since NEP's PTF cos	ts are offset by revenues	it receives un	der the NEPOOL O	ATT, the bill to F	GE		 				
	is typically a small cre	edit or c	harge.					Ť .						
				arginal pricing in March 2	003 reflect bil	lings related to prior	periods.							
				Payments post March 20			i				1			
	(4) See Page 6.											<u> </u>		
	(5) Pursuant to FG&E	Tariff,	M.D.T.E. No. 97, incl	udes costs billed to FG&E	by any other	transmission provi	der, and by region	nal transmission of	or operating					
1 .	entities such as NEP	00L, a	regional transmissior	group, an independent s	ystem operate	or ("ISO"), or any ot	her regional body	, in the event						
	that they are authoriz	ed to bi	I FG&E directly for th	eir services and shall incl	lude any other	charges relating to	the stability of the	e transmission sv	stem.					
				clude working capital cos						 				
				<u> </u>						<u> </u>				
				·		·				 	Land			

Γ			F	itchburg Gas and Electric	: Light Compar	ny d/b/a Unitil			***	T	sc	HEDULE KMA-4
				Monthly External Transmis								Page 3 of 7
				Foreca	st 2005							_
	-											·
	-									MAINE		
			ISO	NEP	NEPOOL			OVER-	i	ELECTRIC (New	COST OF	Total External
Line			ADMINISTRATIVE	COMPREHENSIVE	RN/TRANS.	CONGESTION	CONGESTION	DESIGNATION	NEP TRANS	Brunswick	WORKING	Transmission
#	Month		COSTS (1)	TRANSMISSION (2)	COSTS	PURCHASES (3)	SALES	SALES	CREDIT	Power)	CAPITAL (4)	Costs (5)
		t	Col. A	Col. B	Col. C	Çol. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
····						<u> </u>				-		
1	Jan	Est	\$ 6,500	\$ 2.000	\$ 162,330	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 701	\$ 171,531
	Feb	Est	\$ 1,500					\$ -	 -:	\$ -	\$ 690	
	Mar	Est	\$ 1,500		\$ 144,897		<u> </u>	\$ -	+		\$ 609	
	Apr	Est	\$ 1,500		\$ 151,090			\$ -	+:		\$ 635	
	May	Est	\$ 1,500	\$ 2,000	\$ 138,239		+- <u>-</u>	+:	\$ -	\$ -	\$ 582	
6	Jun	Est	\$ 1,500		\$ 157,157			\$ -	+	 '	\$ 660	
	Jul	Est		\$ 2,000					\$ -		\$ 703	
	Aug	Est	\$ 1,500		\$ 167,266				\$ -	· · · · · · · · · · · · · · · · · · ·	\$ 701	
	Sep	Est	\$ 1,500		\$ 158,109			<u>'</u>	\$ -		\$ 663	
10		Est	\$ 1,500		\$ 144,624				\$ -		\$ 608	
	Nov	Est	\$ 1,500		\$ 154,046				\$ -	\$ -	\$ 647	
	Dec	Est	\$ 1,500		\$ 170,019				\$ -		\$ 712	
13			, ,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	_,	,,	 	· · · · · · · · · · · · · · · · · · ·	<u> </u>	·	·	 	
14												
	Total Forecast 2005	Costs	\$ 23,000	\$ 24.000	\$1,880,171	\$ -	\$ -	\$ -	\$ -	s -	\$ 7,912	\$ 1,935,083
16						·					<u> </u>	
17	2004 External Transi	nission	(Over)/Under Recover	V								\$275,596
18												
19	Computed Interest (S	See page	= 5)						"			\$6,487
20	•	T	1									
21	Costs to be Recover	ed										\$ 2,217,166
22		Ι										
23	Estimated 2005 Total	Deliver	y in kWh									545,735,510
24	,											
25	Proposed 2005 Exte	rnal Trar	nsmission Charge (\$/k	Ŵh)								\$ 0.00406
				Administrative Costs. The			unt was set up to	recover				
				oer 2001, all ISO Administ		e charged/credited						
L				e determination of distribu				1				
				PTF facilities only. Prior t								
L				s are offset by revenues i	t receives unde	er the NEPOOL OA	TT, the bill to FGE		<u> </u>			
	is typically a small cr				L							
				orginal pricing in March 20		ngs related to prior p	eriods.				<u> </u>	
L		ncurred	Reliability Must-Run F	Payments post March 200	3.							
L	(4) See Page 6.	1				ļ	1		ļ			
L	(5) Pursuant to FG&I	E Tariff,	M.D.T.E. No. 97, inclu	des costs billed to FG&E	by any other to	ransmission provide	r, and by regional	transmission or o	perating			
				group, an independent sy								
				eir services and shall inclu		charges relating to the	ne stability of the t	ransmission syste	em.		ļ	
ļ	Effective December	1, 2002,	the ETC shall also inc	lude working capital costs	S		ļ				<u></u>	
				<u> </u>		<u> </u>		<u> </u>		<u> </u>		

Fitchburg Gas and Electric Light Company d/b/a Unitil Calculation of External Transmission Interest - Monthly External Transmission Charge Reconciliation January 2003 - December 2003

	Jan-03 <u>Actual</u>	Feb-03 <u>Actual</u>	Mar-03 <u>Actual</u>	Apr-03 <u>Actual</u>	May-03 <u>Actual</u>	Jun-03 <u>Actual</u>	Jul-03 <u>Actual</u>	Aug-03 <u>Actual</u>	Sep-03 <u>Actual</u>	Oct-03 <u>Actual</u>	Nov-03 <u>Actual</u>	Dec-03 <u>Actual</u>	Total
Total Costs (See page 1)	\$95,842	\$179,068	\$182,318	\$132,667	\$136,835	\$131,439	\$263,417	\$182,211	(\$56,818)	\$213,836	\$116,854	\$148,770	\$1,726,440
Total Revenues	\$134,043	\$157,268	\$148,368	\$143,719	\$138,689	\$139,524	\$159,901	\$165,796	\$153,987	\$146,380	\$143,592	\$165,101	\$1,796,369
(Over)/under Recovery - Month	(\$38,201)	\$21,800	\$33,949	(\$11,051)	(\$1,854)	(\$8,086)	\$103,516	\$16,415	(\$210,804)	\$67,455	(\$26,738)	(\$16,332)	(\$69,930)
CUMULATIVE (OVER)/UNDER RECOVERY Beginning Balance Ending Balance Before Interest	\$213,674 \$175,474	\$176,176 \$197,976	\$198,586 \$232,536	\$233,314 \$222,262	\$223,058 \$221,204	\$222,006 \$213,920	\$214,682 \$318,197	\$319,159 \$335,574	\$336,756 \$125,952	\$126,760 \$194,215	\$194,760 \$168,022	\$168,619 \$152,287	
Average Monthly Balance Interest Rate Number of Days / Month	\$194,574 4.25% 31	\$187,076 4.25% 28	\$215,561 4.25% 31	\$227,788 4.25% 30	\$222,131 4.25% 31	\$217,963 4.25% 30	\$266,439 4.25% 31	\$327,367 4.25% 31	\$231,354 4.25% 30	\$160,487 4.00% 31	\$181,391 4.00% 30	\$160,453 4.00% 31	- 365
Computed Interest	\$702	\$610	\$778	\$796	\$802	\$761	\$962	\$1,182	\$808	\$545	\$596	\$545	\$9,087
Ending Balance with Interest	\$176,176	\$198,586	\$233,314	\$223,058	\$222,006	\$214,682	\$319,159	\$336,756	\$126,760	\$194,760	\$168,619	\$152,832	

Fitchburg Gas and Electric Light Company d/b/a Unitil Calculation of External Transmission Interest - Monthly External Transmission Charge Reconciliation January 2004 - December 2004

	Jan-04 <u>Actual</u>	Feb-04 <u>Actual</u>	Mar-04 <u>Actual</u>	Apr-04 <u>Actual</u>	May-04 <u>Actual</u>	Jun-04 <u>Actual</u>	Jul-04 <u>Actual</u>	Aug-04 <u>Actual</u>	Sep-04 <u>Actual</u>	Oct-04 <u>Estimated</u>	Nov-04 Estimated	Dec-04 Estimated	Total
Total Costs (See page 2)	\$212,631	\$33,486	\$151,241	\$194,266	\$246,967	(\$4,810)	\$152,716	\$203,184	\$115,985	\$136,613	\$145,109	\$159,810	\$1,747,199
Total Revenues (See page 7)	\$154,888	\$137,602	\$137,878	\$133,842	\$124,282	\$132,702	\$133,048	\$141,065	\$141,119	\$126,553	\$127,304	\$142,715	\$1,632,998
(Over)/under Recovery - Month	\$57,743	(\$104,116)	\$13,363	\$60,424	\$122,685	(\$137,513)	\$19,668	\$62,119	(\$25,134)	\$10,060	\$17,805	\$17,096	\$114,201
CUMULATIVE (OVER)/UNDER RECOVERY Beginning Balance Ending Balance Before Interest	\$152,832 \$210,575	\$211,191 \$107,075	\$107,579 \$120,942	\$121,329 \$181,754	\$182,250 \$304,936	\$305,761 \$168,248	\$169,029 \$188.697	\$189,303 \$251,422	\$252,168 \$227,035	\$227,820 \$237,880	\$238,768 \$256.573	\$257,487 \$274,583	
Average Monthly Balance Interest Rate Number of Days / Month	\$181,704 4.00% 31	\$159,133 4.00% 29	\$114,261 4.00% 31	\$151,541 4.00% 30	\$243,593 4.00% 31	\$237,005 4.00% 30	\$178,863 4.00% 31	\$220,362 4.00% 31	\$239,602 4.00% 30	\$232,850 4.50% 31	\$247,671 4.50% 30	\$266,035 4,50% 31	- 366
Computed Interest	\$616	\$504	\$387	\$497	\$825	\$780	\$606	\$747	\$786	\$888	\$914	\$1,014	\$8,563
Ending Balance with Interest	\$211,191	\$107,579	\$121,329	\$182,250	\$305,761	\$169,029	\$189,303	\$252,168	\$227,820	\$238,768	\$257,487	\$275,596	

Fitchburg Gas and Electric Light Company d/b/a Unitil Calculation of External Transmission Interest - Monthly External Transmission Charge Reconciliation January 2005 - December 2005

SCHEDULE KMA-4 Page 5 of 7

	Jan-05 Estimated	Feb-05 <u>Estimated</u>	Mar-05 <u>Estimated</u>	Apr-05 Estimated	May-05 Estimated	Jun-05 <u>Estimated</u>	Jul-05 <u>Estimated</u>	Aug-05 Estimated	Sep-05 <u>Estimated</u>	Oct-05 Estimated	Nov-05 <u>Estimated</u>	Dec-05 Estimated	Total
Total Costs (See page 3)	\$171,531	\$168,866	\$149,006	\$155,224	\$142,321	\$ 161,317	\$171,923	\$171,467	\$162,273	\$148,732	\$158,193	\$174,231	\$1,935,083
Total Revenues (See page 7)	\$197,083	\$188,509	\$183,330	\$182,225	\$168,658	\$184,677	\$193,334	\$192,720	\$185,857	\$172,203	\$173,260	\$193,831	\$2,215,686
(Over)/under Recovery - Month	(\$25,552)	(\$19,643)	(\$34,324)	(\$27,000)	(\$26,338)	(\$23,360)	(\$21,410)	(\$21,254)	(\$23,584)	(\$23,471)	(\$15,067)	(\$19,600)	(\$280,603)
CUMULATIVE (OVER)/UNDER RECOVERY Beginning Balance Ending Balance Before Interest	\$275,596 \$250,045	\$251,161 \$231,518	\$232,444 \$198,119	\$199,034 \$172,033	\$172,796 \$146,458	\$147,136 \$123,776	\$124,332 \$102,922	\$103,405 \$82,151	\$82,545 \$58,961	\$59,252 \$35,781	\$35,983 \$20,916	\$21,032 \$1,432	
Average Monthly Balance Interest Rate Number of Days / Month	\$262,821 5.00% 31	\$241,339 5.00% 28	\$215,282 5.00% 31	\$185,533 5.00% 30	\$159,627 5.00% 31	\$135,456 5.00% 30	\$113,627 5.00% 31	\$92,778 5.00% 31	\$70,753 5.00% 30	\$47,516 5.00% 31	\$28,449 5.00% 30	\$11,232 5.00% 31	- 365
Computed Interest	\$1,116	\$926	\$914	\$762	\$678	\$557	\$483	\$394	\$291	\$202	\$117	\$48	\$6,487
Ending Balance with Interest	\$251,161	\$232,444	\$199,034	\$172,796	\$147,136	\$124,332	\$103,405	\$82,545	\$59,252	\$35,983	\$21,032	\$1,480	

Fitchburg Gas and Electric Light Company d/b/a Unitil Calculation of Working Capital for External Transmission

SCHEDULE KMA-4
Page 6 of 7

	Dec-02 Actual	Jan-03 Actual	Feb-03 Actual	Mar-03 Actual	Apr-03 Actual	May-03 Actual	Jun-03 Actual	Jul-03 Actual	Aug-03 Actual	Sep-03 Actual	Oct-03 Actual	Nov-03 Actual	Dec-03 Actual	Page 6 of 7 Total
1 Total Transmission Expense	\$145,878	\$95,384	\$178,211	\$181,446	\$132,033	\$136,181	\$130.810	\$262,157	\$181,340	(\$56,546)	\$213.907	\$116.375	\$148,159	\$1.865.335
2 Number of Days of Lag / 365 (13.49/365)	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	3.70%	3.70%	3.70%	Ψ1,000,000
3 Working Capital Requirement (L.1 * L.2)	\$6,291	\$4,113	\$7,685	\$7,825	\$5,694	\$5,873	\$5,641	\$11,305	\$7,820	(\$2,438)	\$7,906	\$4.301	\$5,476	\$77,490
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	ψ11, 100
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4,25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.36%	38.36%	38.36%	38,36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	38.36%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11.14%	11,14%	
8 Cost of Working Capital (L.3 * L.7)	\$701	\$458	\$856	\$872	\$635	\$654	\$629	\$1,260	\$872	(\$272)	(\$72) (1)	\$479	\$610	\$7,683

Line 1: Sum of Col. A-H, Page 1.

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2002/2003 Federal and State combined tax rate.

(1) Includes adjustment of (\$952.81) for correction of number of days of lag calculated at 4.31%. In DTE 02-84 FG&E revised its working capital calculation in Exhibit FG&E-MHC-2.

	Jan-04 Actual	Feb-04 Actual	Mar-04 Actual	Apr-04 Actual	May-04 Actual	Jun-04 Actual	Jul-04 Actual	Aug-04 Actual	Sep-04 Actual	Oct-04 Estimate	Nov-04 Estimate	Dec-04 Estimate	Total
1 Total Transmission Expense	\$211,764	\$33,346	\$150,623	\$193,472	\$246.967	(\$5,800)	\$152.091	\$202,354	\$115.511	\$136.054	\$144,516	\$159,157	\$1,740,055
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	ψ1,7 40 ,000
3 Working Capital Requirement (L.1 * L.2)	\$7,827	\$1,232	\$5,567	\$7,151	\$9,128	(\$214)	\$5,621	\$7,479	\$4,269	\$5,028	\$5,341	\$5,882	\$64,311
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	44.15.1.
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$869	\$137	\$618	\$794	\$1,014	(\$24)	\$624	\$831	\$474	\$559	\$593	\$653	\$7,144

Line 1: Sum of Col. A-H, Page 2.

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

	Jan-05 Estimate	Feb-05 Estimate	Mar-05 Estimate	Apr-05 Estimate	May-05 Estimate	Jun-05 Estimate	Jul-05 Estimate	Aug-05 Estimate	Sep-05 Estimate	Oct-05 Estimate	Nov-05 Estimate	Dec-05 Estimate	Total
1 Total Transmission Expense	\$170.830	\$168.175	\$148.397										
				\$154,590	\$141,739	\$ 160,657	\$171,221	\$170,766	\$161,609	\$148,124	\$157,546	\$173,519	\$1,927,171
2 Number of Days of Lag / 365 (13.49/365)	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	
3 Working Capital Requirement (L.1 * L.2)	\$6,314	\$6,216	\$5,485	\$5,713	\$5,239	\$5,938	\$6,328	\$6,311	\$5.973	\$5,474	\$5,823	\$6,413	
4 Cost of Equity	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
5 Cost of Debt	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	
6 Effective Tax Rate	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	38.03%	
7 Tax Adjusted Cost of Capital (L.5 + (L.4/(1-L.6)))	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	
8 Cost of Working Capital (L.3 * L.7)	\$701	\$690	\$609	\$635	\$582	\$660	\$703	\$701	\$663	\$608	\$647	\$712	\$7,912

Line 1: Sum of Col. A-H, Page 3.

Line 2: Number of Days of Lag as calculated in the Company's Lead/Lag Study, Schedule MHC-7 in DTE 02-84. Revised in Exhibit FG&E-MHC-2.

Line 4: DTE 02-24/25 December 2, 2002 Order.

Line 5: DTE 02-24/25 December 2, 2002 Order.

Line 6: 2004 Federal and State combined tax rate.

	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05		Total
ard R-1																(Jan 05	to Dec 05)
kWh Rate		12,120,624		16,311,121		13,382,701			12,520,402		14,971,599	13,539,307	11,813,132		15,021,367	16	64,397,659
Revenue			\$ 0.00308 \$ 45,196			•				\$ 0.00406 \$ 61,505				\$ 0.00406 \$ 50.533	\$ 0.00406 \$ 60.987	\$	667,454
									·,	V 0.11000	V 55,1155	0 1,010	<u> </u>	+ 00,000	Ψ 00,007	Ψ	007,707
\ssistance R-2 kWh	050 227	1,011,562	1 224 672	4 264 002	1 075 044	4 440 000	4.074.070	005.004	4 0 4 4 0 0 7	4.004.045							
Rate	•		\$ 0.00308	1,361,293 \$ 0.00406	1,275,344 \$ 0.00406	1,116,893 \$ 0,00406	1,074,073	925,664 \$ 0.00406	1,044,927	1,264,315	1,249,499	1,129,963	985,900 \$ 0.00406	1,038,769 \$ 0.00406	1,253,652 \$ 0.00406	•	13,720,292
Revenue			\$ 3,772				\$ 4,361		\$ 4,242			\$ 4,588			\$ 5,090	\$	55,704
Commercial G-1																	
kWh	364,286	377,502	423,683	442,087	440,802	407,369	406,838	370,174	420,237	461,068	445.351	445,812	374.682	388.201	435.420		5,038,040
Rate			\$ 0.00308		\$ 0.00406	\$ 0.00406	\$ 0.00406				\$ 0.00406						0,000,040
Revenue	\$ 1,122	\$ 1,163	\$ 1,305	\$ 1,795	\$ 1,790	\$ 1,654	\$ 1,652	\$ 1,503	\$ 1,706	\$ 1,872	\$ 1,808	\$ 1,810	\$ 1,521	\$ 1,576	\$ 1,768	\$	20,454
Commercial G-2																	
kWh		8,520,011		9,977,660	9,948,659	9,194,106	9,182,118	8,354,635	9,484,528	10,406,062		10,061,728	8,456,361	8,761,488	9,827,190	11	13,705,855
Rate Revenue		\$ 0.00308	\$ 0.00308 \$ 29,452					\$ 0.00406							\$ 0.00406		
Revenue	\$ 25,525	\$ 20,242	φ 29,45Z	\$ 40,509	\$ 40,392	\$ 37,328	\$ 37,279	\$ 33,920	\$ 38,507	\$ 42,249	\$ 40,808	\$ 40,851	\$ 34,333	\$ 35,572	\$ 39,898	\$	461,646
rial G-3																	
kWh		19,016,709		19,980,324		20,665,958		20,468,811				20,122,634		19,748,903	20,617,949	24	14,164,608
Rate Revenue		\$ 0.00308 \$ 58.571	\$ 61,200				\$ 0.00406 \$ 85,210	\$ 0.00406 \$ 83,103							\$ 0.00406 \$ 83,709	¢.	001 200
	- 00,001	V 00,011	Ψ 01,200	Ψ 01,120	Ψ 77,010	Ψ 00,004	Ψ 00,210	Ψ 03,103	¥ 00,114	Ψ 01,270	\$ 02,041	ф 01,090	Ф 02,030	\$ 00,101	à 63,709	<u> </u>	991,308
nal TOU G-4																	
kWh Rate	43,664 \$ 0,00308	45,248	50,783 \$ 0.00308	52,989	52,835 \$ 0.00406	48,828	48,764	44,370	50,370	55,264	53,381	53,436	44,910	46,530	52,190		603,869
Revenue	\$ 134						\$ 0.00408					\$ 0.00406 \$ 217	\$ 0.00406 \$ 182		\$ 0.00406 \$ 212	\$	2,452
												<u> </u>	· · · · · · · · · · · · · · · · · · ·		<u> </u>	<u> </u>	2, 102
nd /or SH G-5 kWh	39,757	41,200	46,240	48.248	48,108	44.450	44.404	40.400	45.004	50.000	10.005	40.055			.=		
Rate		\$ 0.00308				44,459 \$ 0,00406	44,401 \$ 0,00406	40,400 \$ 0.00406	45,864 \$ 0,00406	50,320 \$ 0,00406	48,605 \$ 0,00406	48,655 \$ 0,00406	40,892 \$ 0,00406	42,367 \$ 0,00406	47,521		549,842
Revenue		\$ 127	\$ 142	\$ 196										\$ 172		\$	2,232
by Service Special Con	tract																
kWh	40,419	17,169	5,639	28,392	15,544	20,310	707	33,917	10,437	5,695	51,172	108,678	40,823	17,341	5,695		338,712
Rate			\$ 0.00308			\$ 0.00406	\$ 0.00406	\$ 0.00406		\$ 0.00406			\$ 0.00406				
Revenue	\$ 124	\$ 53	\$ 17	\$ 115	\$ 63	\$ 82	\$ 3	\$ 138	\$ 42	\$ 23	\$ 208	\$ 441	\$ 166	\$ 70	\$ 23	\$	1,375
or Lighting S																	
kWh	252,417	182,473	478,432	340,399	275,818	274,566	268,813	212,128	207,355	208,121	242,115	267,305	254,648	184,704	480,663		3,216,635
Rate Revenue		\$ 0.00308 \$ 562		\$ 0.00406		\$ 0.00406			\$ 0.00406		\$ 0.00406			\$ 0.00406			
Keveriue	4 ///	\$ 562	\$ 1,474	\$ 1,382	\$ 1,120	\$ 1,115	\$ 1,091	\$ 861	\$ 842	\$ 845	\$ 983	\$ 1,085	\$ 1,034	\$ 750	\$ 1,951	\$	13,060
Revenue	\$ 126,553	\$ 127,304	\$ 142,715	\$ 197,083	\$ 188,509	\$ 183,330	\$ 182,225	\$ 168,658	\$ 184,677	\$ 193,334	\$ 192,720	\$ 185,857	\$ 172,203	\$ 173,260	\$ 193,831	\$	2,215,686
	_																
1148																	
kWh Revenue		\$127,304	46,335,899 \$ 142,715	48,542,512				41,541,478					42,414,412				5,735,510
IZEADING	\$ 120,000	Ψ 127,304	φ 142,7 15	φ 197,083	φ 100,509	φ 183,330	Φ 182,225	\$ 168,658	Φ 184,6//	ъ 193,334 -	\$ 192,720	\$ 185,857	\$ 1/2,203	s 1/3,260	\$ 193,831	\$	2,215,686

MONTHLY INTERNAL TRANSMISSION CHARGE RECONCILIATION

	Fito	hbur	Gas and Electric Light Cor	mpany d/b/a U	nitil	-			SCHE	DULE KMA-5
			Internal Transmission Charg							Page 1 of 7
			2003		•					
								-		
				Total Annua	al/Monthly	1	otal Retail			
			Total Annual/Monthly	PTF Re	venue		Internal			
Line		ĺ	Transmission Revenue	Requirement	(NEPOOL	Tr	ansmission		-	
#	Month		Requirement (OATT)	OAT	T)	ŀ	Costs			
			Col. A	Col.	В		Col. C			
			(A)	(B)					
1	·		\$544,130 eff. 6/99	\$256,510 eff	. 12/02				-	
2			\$806,288 eff. 10/03	\$240,578 eff	. 6/03		•		\neg	
3			· · · · · · · · · · · · · · · · · · ·	-					\neg	
4	Jan	Act	\$ 45,344	\$	21,376	\$	66,720	•	+	
	Feb	Act		\$	21,376		66,720		\neg	
	Mar	Act		\$	21,376	\$	66,720		-	
	Apr	Act		\$	21,376	\$	66,720		+	
	May	Act		\$	13,591	\$	58,935		+	
	Jun	Act		\$	27,833	\$	73,177	***	-	
	Jul	Act		\$	20,048	\$	65,392		-	
	Aug	Act		\$	20.048	\$	65,392		-	
	Sep	Act		\$	20,048	\$	65,392		-	 i
	Oct	Act		\$	20,048	\$	65.392		-	
	Nov	Act		s	20,048	\$	109.085			
	Dec	Act		S	20,048	\$	87,239			
16	Dec	ACI	Ψ 07,191	9	20,040	Ψ	01,239		-	
	Total 2003		\$ 609,670	\$	247,216	S	856,886		-	
18			\$ 609,070	Φ	247,210	9	030,000	-	_	
			ssion Charge Revenues			\$	802,846	.		
20		ISITIIS	sion Charge Revenues			Φ.	002,040		_	
					-		54.040			
22	2003 (Over)/under Rec	over	/ 	-		\$	54,040			
	(Over)/under Recovery	L					(800.077)		$-\!\!\!\!-$	
23	(Over)/under Recovery	- 56	g. or rear				(\$32,877)	<u> </u>	_	
	Computed Interest (See		1			-	(4.550)		_	
26	Computed interest (Sec	Pag	je 4)			\$	(1,553)			
	/Over\/vades Deserver		 				40.040			
	(Over)/under Recovery	- <u>En</u>	d of fear			\$	19,610		_	
ļ		<u> </u>				_				
		<u> </u>								
_		 								
 		ļ							-	
├									+	
├—		<u> </u>								
	(A) D	F = -105	M D T E No. 04	ļ	_				$-\!$	
Ь—	(A) Pursuant to FG&E			<u></u>						
<u> </u>			E's FERC-approved Open					B 1 7 22		
ļ			ive June 1, 1999 approved I					Docket ER)O-121	ō-000.
ļ			ive October 1, 2003 approve	ed by FERC in	Docket ER	03-	1410-000.		\dashv	
<u> </u>	\$806,288 total, MBTA p	ortio	n credited as revenue.							
ļ	(5) 5					L_,				
			, M.D.T.E. No. 34. Includes	rG&E's PTF f	Revenue Re	qui	rement			
Щ.	included in NEPOOL O	pen /	Access Transmission Tariff.						L	

			Gas and Electric Light Co			SC	HEDULE KMA-5
	Mor	thly In	ternal Transmission Cha	rge Reconciliation			Page 2 of 7
			Forecast 2004				
		-		T-1-1 A	7.4.15.7.9		
		1	Total Applied/Manthly	Total Annual/Monthly	Total Retail		
Linn			Total Annual/Monthly	PTF Revenue	Internal		
<u>Line</u>	Manth	İ	Transmission Revenue	Requirement (NEPOOL	Transmission		
<u>#</u>	Month .		Requirement (OATT)	OATT)	Costs		
			Col. A	Col. B	Col. C		
1			(A)	(B)			
2			\$806,288 eff. 10/03	\$240,530 eff. 6/03			
- 3		-	\$962,708 eff. 6/04	\$281,040 eff. 6/04			
	Jan	10.04	6 67.404	#0.040.41\	Ď 74407		
		Act		\$6,946 (1)			
	Feb	Act		\$ 20,048			
	Mar	Act			\$ 87,239		
	Apr	Act			\$ 87,239		
	May	Act		\$ 20,048	\$ 87,239		
	Jun	Act	\$ 80,226	\$23,372 (2)			
	Jul	Act	\$ 80,226		\$ 103,646		
	Aug	Act		\$ 23,420	\$ 103,646		
	Sep	Act	\$ 80,226	\$ 23,420	\$ 103,646		
	Oct	Est	\$ 80,226		\$ 103,646		
	Nov	Est			\$ 103,646		
	Dec	Est	\$ 80,226	\$ 23,420	\$ 103,646		
16							
	Total 2004 Forecast		\$ 897,534	\$ 251,031	\$ 1,148,565		
18							
		insmis	sion Charge Revenues		\$ 1,048,114		
20							
	2004 (Over)/under Red	covery			\$ 100,451		
22	<u> </u>	ــــــــــــــــــــــــــــــــــــــ					
	(Over)/under Recovery	\ - Rec	. of Year		\$ 19,610		
24		-					
	Computed Interest				\$ (6,710)		
26		↓ _					
21	(Over)/under Recovery	/ - Enc	of Year		\$ 113,351		
		1					
		_					
	(A) D	J	MDTS W. S.				
	(A) Pursuant to FG&E			L <u> </u>	lee		
_	includes charges unde	r FG&	E's FERC-approved Ope	n Access Transmission T	aritt.		
	Revenue requirement	errecti	ve October 1, 2003 appro	oved by FERC Order date	d November 25, 2	2003 in Docket EF	R03-1410-000.
	\$806,288 total, MBTA			L FERRO L L L L L			
	Revenue requirement	errecti	ve June 1, 2004 accepted	by FERC Order dated S	eptember 28, 200	4 in Docket ER03	3-1410-001.
_	(D) Diversions to COSE	Tif	MDTC No 04 bod of	- FOOFI- DYF D		<u> </u>	
_				s FG&E's PTF Revenue F	kequirement	-	
	included in NEPOOL (pen A	ccess Transmission Tari	π.			
	(4) Adirotes and at 1848	101 7	0) 4- DTE D		W. 5550.0	2010 4 17: 7	
	in OADZ 222 040 013	,101.7	3) to PTF Revenue Requ	irements in compliance w	ith FERC Order of	n RNS Audit Rep	ort
			-013, OA97-237-014 issu		100 11		
	(2) Adjustment of (\$48	.U2) to	correct PTF Revenue Re	equirements from June 20	os through May 2	2004.	
		\perp					

	Fitch	bura	Gas and Electric Light Co	ompany d/b/a Unitil		sc	HEDULE KMA-5
			ternal Transmission Cha				Page 3 of 7
			Forecast 2005				
		1					
				Total Annual/Monthly	Total Retail		
l		1	Total Annual/Monthly	PTF Revenue	internal		
Line		1	Transmission Revenue	Requirement (NEPOOL	Transmission		
#	Month	1	Requirement (OATT)	OATT)	Costs		
			Col. A	Col. B	Col. C		
			(A)	(B)			
1			\$962,708 eff. 6/04	\$281,040 eff. 6/04			
2			\$962,708 eff. 6/05 est.	\$281,040 eff. 6/05 est.			
3							
4	Jan	Est	\$ 80,226	\$23,420	\$ 103,646		
5	Feb	Est	\$ 80,226	\$23,420			
6	Mar	Est	\$ 80,226	\$23,420			
7	Арг	Est		\$23,420			
	May	Est	\$ 80,226	\$23,420			
	Jun	Est		\$23,420			
10	Jul	Est	\$ 80,226	\$23,420			
11	Aug	Est		\$23,420			
12	Sep	Est	\$ 80,226	\$23,420			
13	Oct	Est		\$23,420			
14	Nov	Est	\$ 80,226	\$23,420			
15	Dec	Est	\$ 80,226	\$23,420	\$ 103,646		
16					<u> </u>		
17	Total 2005 Forecast		\$ 962,708	\$ 281,040	\$ 1,243,748		
18							
19	2004 Internal Transmis	sion (Over)/Under Recovery		\$113,351		
20							
21	2005 Computed Interes	t (Se	e page 5)		\$2,733		
22					-		
	Costs to be Recovered	- 200	5		\$ 1,359,832		_
24							
	Less:2005 Internal Tran	smis	sion Charge Revenues		\$ 817,665		
26							
	Total Costs to be Recov	vered			\$ 542,167		
28	· · · · · · · · · · · · · · · · · · ·		***				
	Forecast 2005 Total De	livery	in kWh		545,735,510		
30		ļ					
31	Proposed 2005 ITSCA	(\$/kV\	/h)		\$ 0.00099		
ļ							
		<u> </u>					
\vdash							
<u> </u>					<u> </u>		
	/A\ B	<u></u>	MD75 N 01				
 -	(A) Pursuant to FG&E T	arıtt,	M.D. I.E. No. 34.	<u> </u>			
	Includes charges under	rG8	E's FERC-approved Ope	n Access Transmission T	arım.		700 4446 7
-	Revenue requirement e	Hecti	ve October 1, 2003 appro	oved by FERC Order date	a November 25, 2	2003 in Docket El	RU3-1410-000.
<u> </u>	nevenue requirement e	recti	ve June 1, 2004 accepted	by FERC Order dated S	eptember 28, 200	14 In Docket ERO	3-1410-001.
├	(B) Burguest to ECOF T	oriff	MDTE No 24 leabide	s FG&E's PTF Revenue F	7		
\vdash					requirement		
 	Included in NEPOOL U	pen A	ccess Transmission Tari	II.			
├							
Щ.		Щ.					

chburg Gas and Electric Light Company d/b/a Unitil	
alculation of Internal Transmission Interest - Monthly Internal Transmission Reconciliati	on
nuary 2003 - December 2003	

nualy 2005 - December 2005	Jan-03 <u>Actual</u>	Feb-03 <u>Actual</u>	Mar-03 <u>Actual</u>	Apr-03 <u>Actual</u>	May-03 <u>Actual</u>	Jun-03 <u>Actual</u>	Jul-03 <u>Actual</u>	Aug-03 <u>Actual</u>	Sep-03 <u>Actual</u>	Oct-03 <u>Actual</u>	Nov-03 <u>Actual</u>	Dec-03 <u>Actual</u>	Total
<u>OSTS</u> ital Costs (See page 1)	\$66,720	\$66,720	\$66,720	\$66,720	\$58,935	\$73,177	\$65,392	\$65,392	\$65,392	\$65,392	\$109,085	\$87,239	\$856,886
ernal Transmission Charge Revenues SCA Revenue Forecast	\$80,505 \$0	\$68,643 \$0	\$65,505 \$0	\$62,782 \$0	\$60,659 \$0	\$61,839 \$0	\$70,306 \$0	\$71,726 \$0	\$67,280 \$0	\$62,356 \$0	\$60,250 \$0	\$70,993 \$0	\$802,846 \$0
tal Revenue	\$80,505	\$68,643	\$65,505	\$62,782	\$60,659	\$61,839	\$70,306	\$71,726	\$67,280	\$62,356	\$60,250	\$70,993	\$802,846
ver)/under Recovery - Month	(\$13,785)	(\$1,923)	\$1,215	\$3,938	(\$1,724)	\$11,338	(\$4,913)	(\$6,333)	(\$1,888)	\$3,036	\$48,835	\$16,245	\$54,040
JMULATIVE (OVER)/UNDER RECOVERY													
ginning Balance	(\$32,877)	(\$46,806)	(\$48,885)	(\$47,845)	(\$44,068)	(\$45,982)	(\$34,785)	(\$39.832.38)	(\$46,265.43)	(\$48,318)	(\$45,441)	\$3,325	
iding Balance Before Interest	(\$46,663)	(\$48,730)	(\$47,671)	(\$43,908)	(\$45,792)	(\$34,644)	(\$39,698)	(\$46,166)	(\$48,153)	(\$45,282)	\$3,395	\$19,571	
erage Monthly Balance	(\$39,770)	(\$47,768)	(\$48,278)	(\$45,876)	(\$44,930)	(\$40,313)	(\$37,241)	(\$42,999)	(\$47,209)	(\$46,800)	(\$21,023)	\$11,448	
erest Rate	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	4.00%	4.00%	4.00%	
imber of Days / Month	31	28	31	30	31	30	31	31	30	31	30	31	365
mputed Interest	(\$144)	(\$156)	(\$174)	(\$160)	(\$190)	(\$141)	(\$134)	(\$100)	(\$165)	(\$159)	(\$69)	\$39	(\$1,553)
iding Balance with Interest	(\$46,806)	(\$48,885)	(\$47,845)	(\$44,068)	(\$45,982)	(\$34,785)	(\$39,832)	(\$46,265)	(\$48,318)	(\$45,441)	\$3,325	\$19,610	

chburg Gas and Electric Light Company d/b/a Unitil Identification of Internal Transmission Interest - Monthly Internal Transmission Reconciliation nuary 2004 - December 2004

OSTS	Jan-04 <u>Actual</u>	Feb-04 <u>Actual</u>	Mar-04 <u>Actual</u>	Apr-04 <u>Actual</u>	May-04 <u>Actual</u>	Jun-04 <u>Actual</u>	Jul-04 <u>Actual</u>	Aug-04 <u>Actual</u>	Sep-04 <u>Actual</u>	Oct-04 Estimated	Nov-04 Estimated	Dec-04 Estimated	Total
tal Costs (See page 2)	\$74,137	\$87,239	\$87,239	\$87,239	\$87,239	\$103,598	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$1,148,565
ernal Transmission Charge Revenues (See page 7) SCA Revenue Forecast (See page 7)	\$83,755 \$0	\$87,520 \$0	\$85,250 \$0	\$82,318 \$0	\$77,333 \$0	\$80,971 \$0	\$83,461 \$0	\$128,375 (1) \$0	\$88,036 \$0	\$61,982 \$18,079	\$61,966 \$18,186	\$70,494 \$20,388	\$991,461 \$56,653
tal Revenue (See page 7)	\$83,755	\$87,520	\$85,250	\$82,318	\$77,333	\$80,971	\$83,461	\$128,375	\$88,036	\$80,061	\$80,152	\$90,882	\$1,048,114
/er)/under Recovery - Month	(\$9,618)	(\$281)	\$1,989	\$4,921	\$9,906	\$22,626	\$20,185	(\$24,730)	\$15,610	\$23,585	\$23,494	\$12,764	\$100,451
JMULATIVE (OVER)/UNDER RECOVERY													
ginning Balance	\$19,610	\$10,042	\$9,793	\$11,818	\$16,785	\$26,765	\$49,516	\$69,903	\$36,776	\$52,532	\$76,362	\$100,180	
iding Balance Before Interest	\$9,992	\$9,761	\$11,781	\$16,738	\$26,691	\$49,391	\$69,701	\$45,173	\$52,386	\$76,116	\$99,855	\$112,945	
erage Monthly Balance	\$14,801	\$9,902	\$10,787	\$14,278	\$21,738	\$38,078	\$59,609	\$57,538	\$44,581	\$64,324	\$88,109	\$106,563	
erest Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.50%	4.50%	4.50%	
imber of Days / Month	31	29	31	30	31	30	31	31	30	31	30	31	366
imputed Interest	\$50	\$31	\$37	\$47	\$74	\$125	\$202	(\$8,398) (2)	\$146	\$245	\$325	\$406	(\$6,710)
iding Balance with Interest	\$10,042	\$9,793	\$11,818	\$16,785	\$26,765	\$49,516	\$69,903	\$36,776	\$52,532	\$76,362	\$100,180	\$113,351	

⁽¹⁾ Includes \$39,805.34 for reversal of Transformer Ownership Credits from March 1998 to July 2004 and \$227.18 for MBTA revenue associated with Internal Transmission from October 2003 through August 2004.
(2) Includes interest adjustment of (\$8,592.75) associated with adjustments made to revenue. See note (1).

	Jan-05 <u>Estimated</u>	Feb-05 <u>Estimated</u>	Mar-05 Estimated	Apr-05 <u>Estimated</u>	May-05 Estimated	Jun-05 <u>Estimated</u>	Jul-05 <u>Estimated</u>	Aug-05 Estimated	Sep-05 Estimated	Oct-05 Estimated	Nov-05 Estimated	Dec-05 Estimated	Total
OSTS Ital Costs (See page 3)	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$103,646	\$1,243,748
rernal Transmission Charge Revenues (See page 7) SCA Revenue Forecast (See page 7)	\$73,303 \$48,057	\$70,477 \$45,966	\$66,314 \$44,704	\$65,886 \$44,434	\$61,369 \$41,126	\$66,452 \$45,032	\$72,909 \$47,143	\$71,384 \$46,993	\$69,598 \$45,320	\$63,794 \$41,990	\$63,784 \$42,248	\$72,395 \$47,264	\$817,665 \$540,278
tal Revenue (See page 7)	\$121,360	\$116,443	\$111,017	\$110,321	\$102,495	\$111,484	\$120,052	\$118,377	\$114,918	\$105,784	\$106,032	\$119,660	\$1,357,943
ver)/under Recovery - Month	(\$17,715)	(\$12,798)	(\$7,372)	(\$6,675)	\$1,151	(\$7,838)	(\$16,407)	(\$14,732)	(\$11,272)	(\$2,138)	(\$2,386)	(\$16,014)	(\$114,195)
JMULATIVE (OVER)/UNDER RECOVERY													
ginning Balance	\$113,351	\$96,079	\$83,624	\$76,591	\$70,216	\$71,667	\$64,106	\$47,936	\$33,376	\$22,218	\$20,169	\$17,861	
iding Balance Before Interest	\$95,636	\$83,281	\$76,252	\$69,916	\$71,367	\$63,829	\$47,700	\$33,205	\$22,104	\$20,080	\$17,783	\$1,847	
erage Monthly Balance	\$104,493	\$89,680	\$79,938	\$73,253	\$70,791	\$67,748	\$55,903	\$40,570	\$27,740	\$21,149	\$18,976	\$9,854	
erest Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
imber of Days / Month	31	28	31	30	31	30	31	31	30	31	30	31	365
imputed interest	\$443	\$343	\$339	\$300	\$300	\$278	\$237	\$172	\$114	\$90	\$78	\$42	\$2,733
iding Balance with Interest	\$96.079	\$83.624	\$76.591	\$70.216	\$71.667	\$64 106	\$47 936	\$33,376	\$22 218	\$20 169	\$17.861	\$1.888	

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s Effective January 1, 2005

		Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total (Jan 05 to Dec 05)
dard R-1 kWh Rate Revenue		11,493,534 \$ 0.00192 \$ 22,068		14,674,121 \$ 0.00192 \$ 28,174		15,281,282 \$ 0.00192 \$ 29,340	13,382,701 \$ 0.00192 \$ 25,695		\$ 0.00192				13,539,307 \$ 0.00192 \$ 25,995	11,813,132 \$ 0.00192 \$ 22,681		15,021,367 \$ 0.00192 \$ 28,841	164,397,659
Assistance R-2 kWh Rate Revenue	_	959,227 \$ 0.00192 \$ 1,842	1,011,562 \$ 0.00192 \$ 1,942				1,116,893 \$ 0.00192 \$ 2,144	1,074,073 \$ 0.00192 \$ 2,062	925,664 \$ 0.00192 \$ 1,777	1,044,927 \$ 0.00192 \$ 2,006		1,249,499 \$ 0.00192 \$ 2,399	1,129,963 \$ 0.00192 \$ 2,170		1,038,769 \$ 0.00192 \$ 1,994	1,253,652 \$ 0.00192 \$ 2,407	13,720,292 \$ 26,343
l Commercial G-1 kWh Rate Revenue	=	364,286 \$ 0.00189 \$ 689		423,683 \$ 0.00189 \$ 801		440,802 \$ 0.00189 \$ 833	407,369 \$ 0.00189 \$ 770	406,838 \$ 0.00189 \$ 769		420,237 \$ 0.00189 \$ 794			445,812 \$ 0.00189 \$ 843			435,420 \$ 0.00189 \$ 823	5,038,040 \$ 9,522
∍ Commercial G-2 kWh Rate Revenue		8,221,740 \$ 0.00068 \$ 5,591	8,520,011 \$ 0,00068 \$ 5,794	9,562,302 \$ 0.00068 \$ 6,502		9,948,659 \$ 0.00068 \$ 6,765	9,194,106 \$ 0.00068 \$ 6,252	9,182,118 \$ 0.00068 \$ 6,244	8,354,635 \$ 0.00068 \$ 5,681	9,484,528 \$ 0.00068 \$ 6,449	10,406,062 \$ 0.00068 \$ 7,076	10,051,321 \$ 0.00068 \$ 6,835	10,061,728 \$ 0.00068 \$ 6,842	8,456,361 \$ 0.00068 \$ 5,750	8,761,488 \$ 0.00068 \$ 5,958	9,827,190 \$ 0.00068 \$ 6,682	113,705,855 \$ 77,320
KW Rate Revenue			*	33,876 \$ 0.29 \$ 9,824	33,004 \$ 0.29 \$ 9,571		31,906 \$ 0.29 \$ 9,253	32,685 \$ 0.29 \$ 9,479		35,343 \$ 0.29 \$ 10,250		33,092 \$ 0.29 \$ 9,597	37,179 \$ 0.29 \$ 10,782			34,580 \$ 0.29 \$ 10,028	408,885 \$ 118,577
itrial G-3 kWh Rate Revenue	Ave On/Off_	19,673,436 \$ 0.000545 \$ 10,722	\$ 0.000545	19,870,026 \$ 0,000545 \$ 10,829			\$ 0.000545		20,468,811 \$ 0.000545 \$ 11,156				\$ 0.000545	20,403,065 \$ 0.000545 \$ 11,120	19,748,903 \$ 0.000545 \$ 10,763		244,164,608 \$ 133,070
kVa Rate Revenue		45,222 \$ 0.21 \$ 9,497	43,982 \$ 0.21 \$ 9,236	43,227 \$ 0.21 \$ 9,078			43,062 \$ 0.21 \$ 9,043		\$ 44,675 \$ 0.21 \$ 9,382		48,243 \$ 0.21 \$ 10,131	47,995 \$ 0.21 \$ 10,079	47,880 \$ 0.21 \$ 10,055	46,871 \$ 0.21 \$ 9,843	45,628 \$ 0.21 \$ 9,582		545,642 \$ 114,585
nal TOU G-4 kWn Rate Revenue	Ave On/Off_		45,248 \$ 0.00062 \$ 28	50,783 \$ 0.00062 \$ 31		52,835 \$ 0.00062 \$ 33	48,828 \$ 0.00062 \$ 30		44,370 \$ 0.00062 \$ 28			53,381 \$ 0.00062 \$ 33			46,530 \$ 0.00062 \$ 29	52,190 \$ 0.00062 \$ 32	603,869
KW Rate Revenue	<u>-</u>	64 \$ 0.35 \$ 23		65 \$ 0.35 \$ 23			61 \$ 0.35	63 \$ 0.35	65 \$ 0.35	68 \$ 0.35	71 \$ 0.35	63	71 \$ 0.35	66 \$ 0.35	62 \$ 0.35 \$ 22	66 \$ 0.35	782
	***									-	+ 20	* 22	¥	¥ 20	¥ 22	Ψ 23	2/4

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ind /or SH G-5	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total (Jan 05 to Dec 05)
kWh Rate	39,757 \$ 0.00182	41,200 \$ 0,00182	46,240 \$ 0.00182		48,108 \$ 0.00182	44,459 \$ 0.00182	44,401 \$ 0.00182	40,400 \$ 0,00182	45,864 \$ 0.00182	50,320 \$ 0.00182	48,605 \$ 0.00182	48,655 \$ 0.00182	40,892 \$ 0.00182	42,367 \$ 0.00182	47,521 \$ 0.00182	549,842
Revenue	\$ 72	\$ 75	\$ 84	\$ 88	\$ 88	\$ 81	\$ 81	\$ 74	\$ 83	\$ 92	\$ 88	\$ 89	\$ 74	\$ 77	\$ 86	\$ 1,001
tby Service Special Contract	40.440	47.400	5.000	00.000	45.544											
Rate Ave On/Off	40,419 \$ 0,00055	17,169 \$ 0.00055	5,639 \$ 0.00055	28,392 \$ 0.00055	15,544 \$ 0.00055	20,310 \$ 0.00055	707 \$ 0.00055	33,917 \$ 0.00055	10,437 \$ 0.00055	5,695 \$ 0,00055	51,172 \$ 0.00055	108,678 \$ 0.00055	40,823 \$ 0.00055	17,341 \$ 0.00055	5,695 \$ 0.00055	338,712
Revenue	\$ 22	\$9	\$ 3	\$ 15	\$ 8	\$ 11	\$ 0	\$ 18	\$ 6			\$ 59	\$ 22	\$ 9		\$ 185
kVa Rate	1,885 \$ 0.21	1,885 \$ 0.21	1,885 \$ 0.21	1,785 \$ 0.21	1,904 \$ 0.21	1,949 \$ 0.21	1,904 \$ 0.21	1,904 \$ 0.21	1,904 \$ 0.21	1,904 \$ 0.21	22,176					
Revenue	\$ 396	\$ 396	\$ 396	\$ 375	\$ 375	\$ 375	\$ 375					\$ 400				4,657
oor Lighting S kWh Rate	252,417 \$ 0.00501	0.0000	478,432 \$ 0.00501	340,399 \$ 0.00501	275,818 \$ 0.00501	274,566 \$ 0.00501	268,813 \$ 0.00501	212,128 \$ 0.00501	207,355 \$ 0.00501	208,121 \$ 0.00501	242,115 \$ 0.00501	+ 0.0000,	254,648 \$ 0.00501	184,704 \$ 0.00501	480,663 \$ 0.00501	3,216,635
Revenue	\$ 1,265	\$ 914	\$ 2,397	\$ 1,705	\$ 1,382	\$ 1,376	\$ 1,347	\$ 1,063	\$ 1,039	\$ 1,043	\$ 1,213	\$ 1,339	\$ 1,276	\$ 925	\$ 2,408	16,115
Total Revenue	\$ 61,982	\$ 61,966	\$ 70,494	\$ 73,303	\$ 70,477	\$ 66,314	\$ 65,886	\$ 61,369	\$ 66,452	\$ 72,909	\$ 71,384	\$ 69,598	\$ 63,794	\$ 63,784	\$ 72,395	817,665
A Revenues kWh	41,088,481	41,332,498	46,335,899	48,542,512	46,430,728	45,155,191	44,882,931	41,541,478	45,486,956	47,619,144	47,468,081	45,777,516	42,414,412	42.674.915	47,741,646	545,735,510
ITSCA	\$ 0.00044	\$ 0.00044	\$ 0.00044		\$ 0.00099	\$ 0.00099	\$ 0.00099		\$ 0.00099	\$ 0.00099	\$ 0.00099	\$ 0.00099	\$ 0.00099	\$ 0.00099	\$ 0.00099	
ITSCA Revenues	\$ 18,079	18,186	\$ 20,388	\$ 48,057	\$ 45,966	\$ 44,704	\$ 44,434	\$ 41,126	\$ 45,032	\$ 47,143	\$ 46,993	\$ 45,320	\$ 41,990	\$ 42,248	\$ 47,264	\$ 540,278